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## BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

KRISTIN K. MAYES, Chairman  
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AZ CORP COMMISSION  
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Arizona Corporation Commission

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IN THE MATTER OF THE APPLICATION  
 OF JOHNSON UTILITIES, LLC, DBA  
 JOHNSON UTILITIES COMPANY FOR AN  
 INCREASE IN ITS WATER AND  
 WASTEWATER RATES FOR CUSTOMERS  
 WITHIN PINAL COUNTY, ARIZONA

DOCKET NO. WS-02987A-08-0180

**JOHNSON UTILITIES LLC'S  
 CLOSING BRIEF**

**I. INTRODUCTION.**

On March 31, 2008, Johnson Utilities, LLC, dba Johnson Utilities Company ("Johnson Utilities" or the "Company") filed an application with the Arizona Corporation Commission ("Commission") for a rate increase. The test year used by Johnson Utilities is for the 12-month period ending December 31, 2007. The Company has also proposed certain *pro forma* adjustments to take into account known and measurable changes to rate base, expenses and revenues. These *pro forma* adjustments are consistent with normal ratemaking and with the Commission's rules and regulations. They are also necessary to obtain a normal or *realistic* relationship between revenues, expenses and rate base.

This is the first rate case filed by Johnson Utilities since its original certificate of convenience and necessity ("CC&N") was approved (Decision 60223, May 27, 1997). In that decision, the Company was ordered to file a rate review five years after service started. The Company complied with the order and filed rate reviews. In Decisions 68235, 68236 and 68237 (dated October 25, 2005), the Commission directed the

1 Company to file water and wastewater rate applications by May 1, 2007, based on a  
2 2006 test year. Prior to that filing date and on several occasions thereafter, the Company  
3 filed requests that the Commission extend the filing date. Most recently, on September  
4 18, 2007, Staff recommended that the Company be required to file the applications by  
5 March 31, 2008, utilizing a 2007 Test Year.

6 For its Water Division, Johnson Utilities is requesting a decrease in revenues of  
7 \$2,879,022, or a decrease of 21.86%, for a total revenue requirement of \$10,293,877.  
8 (Exhibit A-4, Volume II at 3). The Company is proposing an adjusted rate base of  
9 \$3,539,562. (Exhibit A-4, Volume II at 3; *see also* Johnson Utilities Notice of Filing  
10 Closing Schedules ("Johnson's Final Schedules") Water Division, Schedule C-1).

11 For its Wastewater Division, Johnson Utilities is requesting an increase in  
12 revenues of \$2,326,532, or an increase of 20.49%, for a total revenue requirement of  
13 \$13,680,546. (Exhibit A-4, Volume III at 3). The Company is proposing an adjusted  
14 rate base of \$17,479,735. (Exhibit A-2, Volume III, page 4; *see also* Johnson's Final  
15 Schedules, Wastewater Division, Schedule B-1).

## 16 **II. REVENUE REQUIREMENT.**

### 17 **A. Water Division.**

18 For its Water Division, Johnson Utilities is requesting a decrease in revenues of  
19 \$2,879,022 (a decrease of 21.86%) for a total revenue requirement of \$10,293,877.  
20 (Exhibit A-4, Volume II at 3).

21 The parties' proposed revenue requirements and proposed rate increases are as  
22 follows:

	<u>Revenue Requirement</u>	<u>Revenue Increase</u>	<u>% Increase</u>
Company <sup>1</sup>	\$10,293,877	\$(2,879,022)	-21.86%
Staff <sup>2</sup>	\$10,156,099	\$(3,018,800)	-22.90%
RUCO <sup>3</sup>	\$13,099,181	\$(73,718)	-.56%

In addition, the Company is proposing a rate of return on equity of 11.89% based on its weighted average cost of capital. (*Id.*).

### **B. Wastewater Division.**

For its Wastewater Division, the Company is requesting an increase in revenues of \$2,326,532 (an increase of 20.49%) for a total revenue requirement of \$13,680,546. (Exhibit A-4, Volume III at 3).

The parties' proposed revenue requirements and proposed rate increases are as follows:

	<u>Revenue Requirement</u>	<u>Revenue Incr.</u>	<u>% Increase</u>
Company <sup>4</sup>	\$13,680,546	\$ 2,326,532	20.49%
Staff <sup>5</sup>	\$10,458,914	\$(895,100)	-7.88%
RUCO <sup>6</sup>	\$10,836,617	\$(515,397)	- 4.54%

## **III. RATE BASE.**

### **A. Water Division.**

The rate bases proposed by each party in the case are as follows:

<sup>1</sup> Exhibit A-4, Volume II at 3; *see also* Johnson's Final Schedules, Water Division, Schedule C-1.

<sup>2</sup> Staff's Notice of Filing Final Schedules, Final Schedule ("Staff's Final Schedule") JMM-W1.

<sup>3</sup> RUCO's Notice of Filing Final Post-Hearing Schedules ("RUCO's Final Schedules"), Water District Schedule SURR RLM-1.

<sup>4</sup> Exhibit A-4, Volume III at 3; *see also* Johnson's Final Schedules, Wastewater Division, Schedule C-1.

<sup>5</sup> Staff's Final Schedule JMM-WW1.

<sup>6</sup> RUCO's Final Schedules, Wastewater District Schedule SURR RLM-1.

	<u>OCRB</u>	<u>FVRB</u>
Company <sup>7</sup>	\$3,539,562	\$3,539,562
Staff <sup>8</sup>	\$(13,863,166)	\$(13,863,166)
RUCO <sup>9</sup>	\$(5,556,766)	\$(5,556,766)

**1. Plant-in-Service.**

**a. Affiliate Profit.**

Johnson Utilities supports an adjustment of \$469,832 to plant-in-service to remove affiliate profit on affiliate-constructed water plant totaling \$26,847,516. (Exhibit A-2, Volume II at 4). The affiliate profit percentage on affiliate contracts is 1.75% of the actual affiliate-constructed plant. (Exhibit A-2, Volume II at 4-5). In contrast, Staff proposes removing \$5,017,752 from plant-in-service for affiliate profit.<sup>10</sup> Staff improperly utilized an affiliate profit percentage of 7.50% for all plant-in-service, regardless of whether such plant was constructed by an affiliate of Johnson Utilities or an unrelated third-party.

Staff's proposed adjustment is overstated for two reasons. First, Staff improperly assumed that all plant recorded on the Company's books was constructed by affiliates. In its response to Staff Data Request JMM 9.2, Johnson Utilities provided Staff with a complete listing of all water plant that was constructed by affiliates of the Company. (Exhibit A-2, Volume II at 5). Based upon this information, affiliate-constructed water plant totaled \$26,847,516, which is fully consistent with the plant documentation (*i.e.*, contracts, invoices, cancelled checks, line extension agreements, etc.) provided by the Company in response to Staff Data Request JMM 1.43. (*Id.*).

Second, the affiliate profit percentage of 7.5% used by Staff is grossly overstated.

<sup>7</sup> Exhibit A-4, Volume III at 4; *see also* Johnson's Final Schedules Water Division, Schedule B-1.

<sup>8</sup> Staff's Final Schedule JMM-W2.

<sup>9</sup> RUCO's Final Schedules, Water District Schedule SURR RLM-2.

<sup>10</sup> Staff's Final Schedule JMM-W3

1 Although Staff asserted that affiliate profit included in the affiliate contracts ranged from  
2 5% to 10% (Exhibit S-38 at 14), the affiliate contracts and the responses provided to  
3 Staff by the Company in its data responses (Staff data requests JMM 1-43 and JMM 4-2)  
4 clearly show that the affiliate contracts included a mark-up of 5-10% for affiliate profit  
5 and overhead—not just affiliate profit. (Exhibit A-2, Volume II at 5-6). Further, as  
6 explained by the Company in response to Staff Data Request JMM 9-2, the Company's  
7 affiliate added 10% to the base contract cost to cover overhead and profit. (Exhibit A-2,  
8 Volume II at 6). Thus, affiliate profit represented only 2% of the base contract cost.  
9 (*Id.*). Moreover, the Company pointed out that the total contract costs that Staff received  
10 (and ultimately used in its analysis) included not only the base contract costs, but taxes,  
11 overhead, and profit. (*Id.*). In order to calculate the 2% affiliate profit on the base  
12 contract amount, the total contract price must be multiplied by 1.75%. (*Id.*). Even if  
13 Staff was correct and affiliate profit was 7.5%, it would apply only to the base contract  
14 costs and the correct percentage to apply to the total contract cost would be only 6.7%.  
15 (Exhibit A-2, Volume II at 7).

16 **b. Inadequately Supported Plant.**

17 The Company removed \$885,064 from plant-in-service, which  
18 represented the amount for which the Company was unable to provide supporting  
19 documentation. (Exhibit A-2, Volume II at 7). In response to Staff Data Requests JMM  
20 1-44 and JMM 9-1, the Company provided contracts, invoices, cancelled checks, and/or  
21 line extension agreements to support its plant costs. (*Id.*). In addition, in responses to  
22 Staff Data Requests JMM 1-43, JMM 1-44, JMM 4-1, JMM 4-2, JMM 4-3, JMM 7-1,  
23 JMM 7-2, JMM 9-1, JMM 9-2, and JMM 12-1, the Company provided its accounting  
24 records, bank statements, plant schedules, reconciliations and other information  
25 supporting plant costs. (Exhibit A-2, Volume II at 7-8).

26 Set forth below is a summary of the plant costs and the supporting documentation

provided by Johnson Utilities to Staff:

<u>Type of Documentation</u>	<u>Cost Booked</u>
LXA only	\$23,126,031
LXA plus back-up	\$15,402,986
Invoices	\$ 5,703,569
Contracts, cancelled checks, bank statements	\$29,222,823
Plant costs booked in an earlier year but subsequently removed and not in test year rate base	\$ 81,087
Total	\$73,536,516
Total requested by Staff	\$74,421,579
Missing documentation	\$ 885,064

Exhibit A-4, Volume II at 13-14).

Despite all of the documentation provided, Staff recommended decreasing plant-in-service by an staggering \$7,433,707.<sup>11</sup> Rather than identifying and removing specific plant costs which Staff found to be unsupported or inadequately supported, Staff determined that “a minimal 10% disallowance is warranted” for all plant-in-service. (Exhibit S-38 at 14). This action by Staff is nearly impossible to justify. In response to a question on cross-examination regarding whether copies of line extension agreements, construction agreements, invoices, receipts, and other supporting documentation is the type of documentation that a utility would submit to substantiate plant costs, Staff witness Michlik responded: “Yes.” (Tr. Vol. IX at 1643 [Michlik]).

Staff’s rationale is entirely arbitrary and Staff gives no supportable basis for its 10% reduction to plant-in-service other than stating that Staff sometimes recommends disallowances in the range of 10% to 100%. (Exhibit S-38 at 14; *see also* Exhibit A-2, Volume II at 9). In fact, the Staff witness admitted on cross examination that he did not identify in his testimony any specific item of plant that was inadequately documented by Johnson Utilities. (Tr. Vol. XI at 1661 [Michlik]). Instead, the Staff witness opted to

<sup>11</sup> Staff’s Final Schedule JMM-W3.

1 make a blanket disallowance. (*Id.*). Because the disallowance did not apply to any  
2 specific item of plant, the Company never received sufficient information to challenge  
3 the disallowance or raise a reasonable defense regarding the plant costs that were  
4 disallowed. (Exhibit A-2, Volume II at 9). Even though there may have been some  
5 plant which Staff determined was fully supported, 10% of those costs were also  
6 disallowed based on this “shotgun” approach. (*Id.*).

7 In addition, Staff’s adjustments for inadequately supported plant are one-sided  
8 and fail to consider corresponding adjustments associated with advances in aid of  
9 construction (“AIAC”) and contributions-in-aid of construction (“CIAC”) related to this  
10 plant. (*Id.*). Based upon the Company’s initial filing, AIAC funded approximately 61%  
11 of the net plant-in-service and CIAC funded approximately 32% of the net plant-in-  
12 service. (*Id.*). In making its disallowance for inadequately supported plant, Staff  
13 completely ignored the sources of funding and failed to make an adjustment to either  
14 AIAC or CIAC associated with the disallowed plant. (*Id.*). To ignore the necessary  
15 corresponding adjustments to AIAC and CIAC creates a mismatch and results in an  
16 understatement of rate base to the detriment of Johnson Utilities. (*Id.*). Thus, Staff has  
17 violated the so-called matching principle of rate-making.

18 **c. Plant Not Used and Useful.**

19 Johnson Utilities proposes to remove \$3,395,894 of plant not used  
20 and useful from plant-in-service. (Exhibit A-2, Volume II at 11). Staff proposes to  
21 remove \$4,127,019 of plant not used and useful from plant-in-service. (Exhibit S-36,  
22 Exhibit MSJ at 11). The Company accepted the removal of \$40,000 for 303-Land  
23 (Ellsworth Wells 1, 2 & 3), \$740,536 for 307–Wells and Springs (Anthem Well #3),  
24 \$745,755 for 307–Wells and Springs (Anthem Well #4), \$526,273 for 307–Wells and  
25 Springs (Crestfield Manor Well #1), \$21,858 for 331-Transmission and Distribution  
26 Mains (San Tan Well #1), \$405,322 for 331-Transmission and Distribution Mains

1 (Magma 2 subdivision), \$824,322 for 331-Transmission and Distribution Mains (Quail  
2 Run Estates), and \$91,828 for 331-Transmission and Distribution Mains (Circle Cross  
3 parcel 12). (*Id.*).

4 However, Johnson Utilities disagrees with the removal of \$731,125 for 331-  
5 Transmission and Distribution Mains (Ricke Water plant 4 miles of 12-inch mains).  
6 (*Id.*; see also Exhibit A-4, Volume II at 7). While this water transmission main is not  
7 currently used to serve customers, the Company was required to build this plant in order  
8 to serve a development. (*Id.*). Although the developer has since had financial trouble  
9 and the development was placed on hold, the Company was obligated to construct this  
10 plant and acted prudently in order to provide service. (Exhibit A-2, Volume II at 11-12).  
11 Johnson Utilities holds the CC&N to provide water service to Silverado Ranch. (Exhibit  
12 A-7 at 14). The Company received a *bona fide* request for water service from the  
13 developer, which obligated Johnson Utilities to serve under its CC&N. (*Id.*). Johnson  
14 Utilities entered into the Silverado Ranch Master Utility Agreement in good faith, which  
15 contractually obligated the Company to construct the water main. (*Id.*). Further, the  
16 water main was constructed within a roadway that has already been paved by the  
17 developer, and the water main is in place and ready to provide water to customers within  
18 Silverado Ranch once homes are constructed. (*Id.*). Johnson Utilities provided  
19 uncontroverted evidence and testimony that the decision to construct the water main was  
20 prudent. Thus, it would be inappropriate and inequitable to remove the \$731,125 cost of  
21 the water main from rate base. (*Id.*).

22 Moreover, all of the plant costs for which the Company and Staff are in  
23 agreement were funded with either CIAC or AIAC. (Exhibit A-2, Volume II at 12).  
24 Although Staff made the corresponding adjustments to CIAC and AIAC for plant that  
25 was disallowed as not "used and useful, (see Exhibit S-38 at 3), RUCO did not. (Exhibit  
26 A-4, Volume II at 8). By failing to make the corresponding adjustments to the CIAC

1 and AIAC accounts, RUCO's adjustments are one-sided and result in a rate base  
2 mismatch as well as a proposed rate base for the Company that is understated. (Exhibit  
3 A-4, Volume II at 9). In fact, the RUCO witness admitted at hearing that his  
4 recommendation would result in a mismatch. (Tr. Vol. II at 184 [Moore]).

5 **d. Excess Capacity.**

6 Staff proposes an excess capacity adjustment of \$433,238 for the  
7 307-Wells and Springs (Anthem-Rancho Sendero Well #1) and \$693,827 for the 330-  
8 Distribution Reservoirs and Standpipe (Anthem-Rancho Sendero WP -0.5 MG).<sup>12</sup> The  
9 basis for Staff's disallowance is that the Rancho Sendero Well #1 and the 0.5 million  
10 gallon storage tank adjacent to the Rancho Sendero wells are not needed to serve Staff's  
11 growth projection of 1,780 customers at the end of 2012.<sup>13</sup> Yet, the evidence shows that  
12 the well and storage tank that Staff removed as excess capacity are, in fact, necessary  
13 and integral to the operation of the Anthem at Merrill Ranch water system. (Exhibit A-5  
14 at 6). The Anthem at Merrill Ranch system has two water plants which each connect to  
15 the distribution system. (*Id.*). The first water plant is comprised of a 1.0 million gallon  
16 storage tank and Anthem Well #1, a 600 gallon-per-minute ("GPM") well located  
17 adjacent to the storage tank. (*Id.*). The second water plant is comprised of (i) a 0.5  
18 million gallon storage tank; (ii) the adjacent Rancho Sendero Well #1, a 600 GPM well;  
19 and (iii) the adjacent Rancho Sendero Well #2, a 300 GPM well. (*Id.*). All three wells  
20 and both storage tanks are necessary to provide safe and reliable water service to  
21 Anthem at Merrill Ranch. (*Id.*).

22 There are three fundamental problems with Staff's recommendation. (Exhibit A-  
23 5 at 7). First, Staff has substantially underestimated customer growth through 2012 at  
24

25 <sup>12</sup> Exhibit S-38 at 9; Exhibit S-36, Exhibit MSJ at 12.

26 <sup>13</sup> *Id.*

1 Anthem at Merrill Ranch. (*Id.*). Staff states that there were 857 customers on the  
2 Anthem water system at the end of test year 2007. Staff then uses a linear regression  
3 analysis<sup>14</sup> to reach an estimate of 1,780 customers at the end of 2012, for an average  
4 growth rate of approximately 185 customers per year. (*Id.*). However, in 2008, a year  
5 for which the Company provided actual data, Johnson Utilities added 366 customers.  
6 (*Id.*). In fact, the Staff witness testified that he had no reason to dispute that 366  
7 customers were added. (Tr. Vol. X at 1459 [Scott]). The number 366 is approximately  
8 twice Staff's estimated average annual growth rate of 185 customers. (*Id.*). Multiplying  
9 366 by five years and adding that number to the test year-end customer count of 857  
10 produces a customer count of 2,687 at the end of 2012. (Exhibit A-5 at 8).<sup>15</sup>  
11 Furthermore, Staff acknowledged that its lineal regression analysis, used to estimate  
12 customer growth, utilized four data points (September, October, November, and  
13 December) from which home sales are typically significantly lower than they are at  
14 earlier times of the year. (Tr. Vol. X at 1519 [Scott]).

15 Based upon an estimate of 2,687 customers at the end of 2012, there is no excess  
16 capacity in the well production capacity or the storage capacity at Anthem at Merrill  
17 Ranch. (Exhibit A-5 at 9). The three wells in the Anthem at Merrill Ranch water system  
18 have a combined pumping capacity of 1,500 GPM. (*Id.*). The two storage tanks have a  
19 combined storage capacity of 1.5 million gallons. (*Id.*). If the Rancho Sendero Well #1  
20 (600 GPM of pumping capacity) were removed as excess capacity, this would leave  
21 Johnson Utilities with only 900 GPM of combined pumping capacity from Rancho  
22 Sendero Well #1 and Anthem Well #1.<sup>16</sup> (*Id.*). Using Staff's peak capacity factor of

23  
24 <sup>14</sup> Exhibit S-36, Exhibit MSJ at 22.

25 <sup>15</sup> In fact, Johnson Utilities introduces a letter from Pulte Homes indicating the following  
estimates: for 2010, 290 lots sold; for 2011, 559 lots sold; and for 2012 and beyond, 500 lots  
sold. (Exhibit A-52).

26 <sup>16</sup> See Exhibit S-36, Exhibit MSJ at 9.

1 0.35 GPM<sup>17</sup> per service connection, and multiplying by 2,687 service connections,  
2 produces a well capacity requirement of just over 940 GPM. (*Id.*). This calculation was  
3 confirmed by Staff during the hearing. (Tr. Vol. X at 1467 [Scott]). Thus, the combined  
4 pumping capacity of 900 GPM from Rancho Sendero Well #1 and Anthem Well #1 is  
5 less than the 940 GPM that would be required to meet customer demand using Johnson  
6 Utilities' conservative estimate of 2,687 customers at the end of 2012. (*Id.*).

7 Staff has also recommended removing the 0.5 million gallon storage tank as  
8 excess capacity.<sup>18</sup> This would leave Anthem at Merrill Ranch with only 1.0 million  
9 gallons of storage in a single tank. (*Id.*). Using Staff's peak factor of 400 gallons per  
10 day of storage capacity per service connection,<sup>19</sup> then multiplying by 2,687 service  
11 connections at the end of 2012, then adding Staff's figure of 120,000 gallons per day for  
12 fire flow, produces a storage capacity requirement of 1,194,800 gallons. (*Id.*). This  
13 storage requirement exceeds the storage capacity of the 1.0 million gallon tank by  
14 approximately 20%. (*Id.*).

15 A second problem with Staff's recommendation is that the removal of the 600  
16 GPM Rancho Sendero Well #1 will create safety and reliability concerns for Johnson  
17 Utilities and its customers. (Exhibit A-5 at 10). Such removal would leave Johnson  
18 Utilities with the 600 GPM Anthem Well #1 and the 300 GPM Rancho Sendero Well #2.  
19 (*Id.*). If the Anthem Well #1 was taken off-line for service—or if the well was lost due  
20 to a lightning strike—that would leave the Company with only the 300 GPM Rancho  
21 Sendero Well #2 to serve all of Anthem at Merrill Ranch. (*Id.*). As of December 31,  
22 2008, Johnson Utilities was serving 1,223 customers in its Anthem at Merrill Ranch  
23 water system. (*Id.*). Using Staff's peak factor of 0.35 GPM and multiplying by 1,223

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24 <sup>17</sup> *Id.*

25 <sup>18</sup> *Id.*

26 <sup>19</sup> *Id.*

1 customers produces a required well production capacity of 428 GPM. (*Id.*). As a result,  
2 the 300 GPM Rancho Sendero Well #1 could not keep up with demand in the event of  
3 the loss of Anthem Well #1. (*Id.*).

4 Further, pursuant to Arizona Administrative Code R18-5-503, Johnson Utilities  
5 must maintain storage for the average daily demand peak flow for a minimum of one  
6 day. (*Id.*). For system design and planning purposes, Johnson Utilities uses a figure of  
7 260 gallons per household per day for customer usage. (*Id.*). Multiplying 260 gallons  
8 by the 2,687 customers at the end of 2012, and then multiplying that number by two (for  
9 two days' worth of storage) produces a storage requirement of 1,397,240 gallons.  
10 (Exhibit A-5 at 10-11). This storage requirement exceeds the capacity of the 1.0 million  
11 gallon tank without allowing for fire flow storage, thereby creating serious safety and  
12 reliability concerns for the Anthem at Merrill Ranch water system if the 0.5 million  
13 gallon tank is removed as excess capacity. (Exhibit A-5 at 11).

14 A third problem with Staff's recommendation is that both Rancho Sendero Well  
15 #1 and Rancho Sendero Well #2 pump directly into the 0.5 million gallon storage tank,  
16 as opposed to the distribution system. (*Id.*). Therefore, it is not possible to pump  
17 Rancho Sendero Well #2 into the water distribution system without going through the  
18 0.5 million gallon storage tank. (*Id.*). At hearing, the Staff witness agreed modifying the  
19 water system to directly connect Rancho Sendero Well #2 to the distribution system  
20 would be expensive, and more importantly, would remove important redundancy and  
21 water production capability. (*Id.*; see also Tr. Vol. X at 1484 [Scott]). Thus, the Staff  
22 witness acknowledged that the storage tank will continue to be used as part of the  
23 operating distribution system despite the fact that Staff has recommended its  
24 disallowance. (Tr. Vol. X at 1485 [Scott]). This is inequitable. Since Staff  
25 acknowledged that the storage tank will continue to be used as part of the water system,  
26 the cost of that storage tank should be included in rate base and considered used and

1 useful.

2 If Staff's recommendation is adopted, Staff agrees with the Company that a  
3 corresponding adjustment to CIAC must be made or a mismatch will occur that will  
4 result in the understatement of rate base. (Exhibit A-4, Volume II at 8). Both projects  
5 for Anthem at Merrill Ranch were fully with CIAC in the amount of \$1,127,065.  
6 (Exhibit A-2, Volume II at 14). Therefore, a corresponding reduction of \$1,127,065  
7 must be made to CIAC in order to properly match Staff's plant-in-service adjustment.  
8 (*Id.*). The net decrease in rate base should be zero (\$433,238 plus \$693,827 minus  
9 \$1,127,065). (*Id.*). Although RUCO adopted Staff's used and useful adjustment, RUCO  
10 failed to make the corresponding adjustment to CIAC. (Exhibit A-4, Volume II at 8).  
11 As stated above, by failing to make the corresponding adjustments to the CIAC account,  
12 RUCO's adjustments are one-sided and result in a rate base mismatch as well as a  
13 proposed rate base for the Company that is understated. (Exhibit A-4, Volume II at 9).  
14 RUCO admitted at hearing that its recommendation would result in a mismatch. (Tr.  
15 Vol. II at 184 [Moore]).

16 **e. Working Capital.**

17 All the parties are in agreement on zero working capital. (Exhibit  
18 A-4, Volume II at 17).

19 **f. Accumulated Depreciation.**

20 All the parties are recommending the same depreciation rates.  
21 (Exhibit A-2, Volume II at 21). The Company is proposing a reduction in the amount of  
22 \$5,662,795 to reflect changes to accumulated depreciation from the plant-in-service  
23 adjustments adopted in its rebuttal case. (Exhibit A-2, Volume II at 15; Johnson's Final  
24 Schedules, Water Division, Schedule B-1).

25 **g. Unexpended Hook-up Fees (CIAC).**

26 Johnson Utilities opposes the recommendation of Staff and RUCO

1 to include \$6,931,078 of unexpended hook-up fees (*i.e.*, CIAC) in rate base. (Exhibit A-  
2 2, Volume II at 15). The Company collects hook-up fees ("HUFs") in advance of the  
3 time the Company will be expected to provide service to the customers for whom the  
4 HUFs are credited. (*Id.*). The period between the time a HUF is collected, the time the  
5 capital improvements to provide capacity are constructed, and the date that a customer  
6 connects to the system can be a year or longer. (*Id.*). Thus, for a period of time, the  
7 customer who is credited with the HUF is not present on the system and the plant  
8 required to serve that future customer is not constructed and recorded in plant. (*Id.*).  
9 Including the unexpended HUFs in rate base not only creates a mismatch in rate base,  
10 but existing ratepayers receive a windfall because existing rate payers get credit for  
11 HUFs paid on behalf of future customers who have not yet connected to the system.  
12 (Exhibit A-2, Volume II at 15-16). The capacity to serve those future customers has not  
13 been constructed, nor has cost of the future capacity been reflected in rate base. (Exhibit  
14 A-2, Volume II at 16). The Company's collection of HUFs ensures that funds are  
15 available for new and needed capacity when construction begins, not after-the-fact.  
16 (*Id.*). The evidence in this case is uncontroverted that these funds are restricted and can  
17 only be spent on new capacity. (Exhibit A-2, Volume II at 17). The evidence in this  
18 case is also uncontroverted that the Company does not benefit from excluding  
19 unexpended CIAC from rate base, and that existing rate payers are not harmed in any  
20 way. (*Id.*).

21 Staff excludes both the plant costs and related CIAC and AIAC from rate base for  
22 its proposed plant not used and useful and excess capacity adjustments, presumably to  
23 recognize the rate base mismatch that would occur if the corresponding adjustments are  
24 not made. (Exhibit A-4, Volume II at 11). Hypothetically speaking, if Johnson Utilities  
25 had in fact constructed plant with the unexpended HUFs, and Staff had determined that  
26 there was excess capacity in such plant or that such plant was not used and useful, then

1 Staff would have make a corresponding adjustment to CIAC after removing the plant  
2 from rate base, just as Staff is proposing with its "not used and useful" and "excess  
3 capacity" plant adjustments in this case. (*Id.*). Thus, there is no good reason why the  
4 same adjustment should not be made with regard to the unexpended HUFs.

5 **h. Contributions-in-aid of Construction ("CIAC").**

6 The Company has accepted certain plant adjustments by Staff for  
7 plant considered not used and useful. (Exhibit A-2, Volume II at 18). Because some of  
8 this plant was funded with CIAC, an adjustment to CIAC is necessary in order to avoid a  
9 mismatch in rate base. (*Id.*).

10 **i. Amortization of CIAC.**

11 The Company is in agreement with Staff on the use of a 2.5%  
12 composite rate for computing past amortization of CIAC.<sup>20</sup> (*Id.*).

13 **j. Advances-in-aid of Construction ("AIAC").**

14 The Company has accepted certain adjustments from Staff for plant  
15 considered not used and useful. (Exhibit A-2, Volume II, at 19). Because some of this  
16 plant was funded with AIAC, an adjustment to AIAC is necessary in order to avoid a  
17 mismatch in rate base. (*Id.*).

18 **k. Deferred Assets.**

19 In order to help reduce the areas of dispute between the parties, the  
20 Company has accepted Staff's proposed adjustment to remove deferred assets from rate  
21 base.<sup>21</sup> (*Id.*).

22 **l. Customer Deposits.**

23 Staff has agreed to remove its adjustment for customer deposits in  
24

25 <sup>20</sup> Exhibit S-38 at 19.

26 <sup>21</sup> Exhibit S-38 at 22.

the amount of \$378,138. (Tr. Vol. X at 1524[Michlik]). Initially, Staff and RUCO overstated the deduction to rate base by this amount.

**m. Materials and Supplies.**

In order to help reduce the areas of dispute between the parties, the Company has accepted Staff's proposed adjustment to remove materials and supplies from rate base.<sup>22</sup> (Exhibit A-2, Volume II at 20).

**n. Plant Reclassification.**

Staff has accepted the reclassification of certain plant in the amount of \$296,615.<sup>23</sup>

**B. Wastewater Division.**

The rate base proposed by each party in the case is as follows:

	<u>OCRB</u>	<u>FVRB</u>
Company <sup>24</sup>	\$17,479,735	\$17,479,735
Staff <sup>25</sup>	\$136,562	\$136,562
RUCO <sup>26</sup>	\$11,252,776	\$11,252,776

**1. Plant-in-Service.**

**a. Affiliate Profit.**

Johnson Utilities recorded \$800,179 of affiliate profit on affiliate-constructed plant totaling \$45,724,508. (Exhibit A-2, Volume III at 5). The affiliate profit percentage on affiliate contracts is 1.75% of the actual affiliate-constructed plant. (*Id.*). In contrast, Staff removed \$7,352,364 of affiliate profit based on affiliate-

<sup>22</sup> Exhibit S-38 at 20.

<sup>23</sup> Staff's Final Schedule JMM-WW2

<sup>24</sup> A-2, Volume III, page 4; *see also* Johnson's Final Schedules, Wastewater Division, Schedule B-1.

<sup>25</sup> Staff's Final Schedule JMM-WW2.

<sup>26</sup> RUCO's Final Schedules, Wastewater District Schedule SURR RLM-2.

1 constructed wastewater plant which is nearly the entire cost of the Wastewater  
2 Division's plant-in-service cost.<sup>27</sup> Staff improperly used an affiliate profit percentage of  
3 7.50% for plant-in-service, regardless of whether such plant was constructed by an  
4 affiliate of Johnson Utilities or an unrelated third-party.

5 Staff's proposed adjustment is overstated for two reasons. First, Staff improperly  
6 assumed that virtually all plant recorded on the Company's books was constructed by  
7 affiliates. (Exhibit S-44 at 13). However, the Company provided evidence and  
8 testimony that affiliate-constructed wastewater plant totaled only \$45,724,508. (Exhibit  
9 A-2, Volume III at 5). As set forth in Section IV.A.1.a above, the Company provided to  
10 Staff a complete listing of all the plant that was constructed by affiliates. Staff's  
11 proposed adjustment to remove affiliate profit is overly broad.

12 Second, for the reasons discussed in Section IV.A.1.a above, the profit percentage  
13 of 7.5% applied by Staff is grossly overstated. (*Id.*).

14 **b. Inadequately Supported Plant.**

15 Johnson Utilities removed \$1,047,941 from plant-in-service, which  
16 represented the amount for which the Company was unable to provide adequate  
17 supporting documentation. (Exhibit A-2, Volume III at 7). As discussed above, the  
18 Company provided Staff with copies of contracts, invoices, cancelled checks, line  
19 extension agreements, accounting records, bank statements, plant schedules,  
20 reconciliations, and other information to support its plant costs. (*See* Section IV.A.1.b).  
21 Rather than identifying and removing specific plant costs which Staff found to be  
22 unsupported or inadequately supported, Staff made a blanket disallowance. (Tr. Vol. XI  
23 at 1661 [Michlik]). In some cases, the Company provided estimates of plant costs,  
24 which the Staff witness admitted on cross-examination may be used for plant cost

25 \_\_\_\_\_  
26 <sup>27</sup> Staff's Final Schedule JMM-WW3

accounting if actual costs are not known under NARUC accounting. (Tr. Vol. XI at 1648 [Michlik]).<sup>28</sup>

Again, rather than identifying specific plant costs which Staff considered unsupported or inadequately supported, Staff determined that "a minimal 10% disallowance is warranted" for all plant-in-service. (Exhibit S-44 at 15). This action by Staff is nearly impossible to justify. Set forth below is a summary of the plant costs and the supporting documentation provided to Staff:

<u>Type of Documentation</u>	<u>Cost Booked</u>
LXA only	\$ 31,275,040
LXA plus back-up	\$ 20,453,490
Invoices	\$ 8,197,464
Contracts, Cancelled Checks, Bank Statements	\$ 59,806,578
Total	\$126,810,065
Total Request by Staff	\$126,810,065
Missing information	\$ 1,047,941

(Exhibit A-4, Volume III at 12). For the reasons discussed above, Staff's disallowance is not supported by the record in this case and should be disregarded. (See Section IV.A.1.b).

It must also be noted that Staff's unsupported plant adjustments are one-sided and fail to address the necessary corresponding adjustments associated with AIAC and CIAC related to this plant. (Exhibit A-2, Volume III at 9). According to the Company's initial filing, AIAC funded approximately 46% of the net plant-in-service and CIAC funded approximately 39% of net plant-in-service. (*Id.*). Yet, in making its disallowance for inadequately supported plant, Staff completely ignored the sources of funding and failed

<sup>28</sup> Pursuant to the Uniform System of Accounts for Class A Water Utilities, Subsection D, "Utility plant account shall be charged with construction costs estimated, if not known, of the utility plant contributed by others or constructed by the utility using contributed cash or its equivalent." (Exhibit A-55).

1 to make an adjustment to either AIAC or CIAC associated with the disallowed plant.  
2 (*Id.*). As stated above, to ignore the necessary corresponding adjustments to AIAC and  
3 CIAC creates a mismatch and results in an understatement of rate base to the detriment  
4 of Johnson Utilities. Thus, Staff's adjustment violates the so-called matching principle  
5 of rate-making.

6 **c. Plant Not Used and Useful.**

7 Johnson Utilities proposes to remove \$2,209,026 of plant not used  
8 and useful from plant-in-service. (Exhibit A-2, Volume III at 11). Staff proposes to  
9 remove \$4,595,298 of plant not used and useful from plant-in-service. (Exhibit S-36,  
10 Exhibit MSJ at 35). The Company accepts the removal of \$473,527 for 381-Plant  
11 Sewers (Magma 2 Subdivision), \$846,092 for 381-Plant Sewers (Quail Run Estates),  
12 and \$889,407 for 360-Collection Sewers (Ironwood Crossing #2). (Exhibit A-2,  
13 Volume III at 11).

14 However, Johnson Utilities disagrees with the removal of \$690,186 for 360-  
15 Collections Sewer Force (Magma approx. 4 miles of 8-inch). (*Id.*). While this plant is  
16 not currently serving customers, the Company was required to build this plant in order to  
17 serve a development. (*Id.*). Although the developer has since had financial trouble and  
18 the development was placed on hold, the Company was obligated to construct this plant  
19 and acted prudently in order to provide service. (Exhibit A-2, Volume III at 12). In  
20 addition, the Company disagrees with the removal of \$1,695,816 for the cost of the  
21 Precision WRP-Marwood Plant consisting of 354-Structures and Improvements for  
22 \$14,491, 381-Plant Sewers for \$5,749, and 381 - Plant Sewers for \$1,675,846. Because  
23 the plant was not only required by ADEQ, but was required to allow subdivision  
24 approvals, the Company believes that this plant should be considered used and useful.  
25 (*Id.*).

26 The Precision wastewater treatment plant ("Precision WWTP") is located

1 adjacent to and south of Bella Vista Road within the Johnson Ranch development.  
2 (Exhibit A-5 at 36). ADEQ issued Aquifer Protection Permit ("APP") No. P-105004 for  
3 the Precision WWTP on April 8, 2004 authorizing the collection and treatment of an  
4 average monthly flow of 0.3 million gallons per day ("MGD") of wastewater. (*Id.*).  
5 While the Precision WWTP is not currently in use, the decision by Johnson Utilities to  
6 build the plant was unavoidable, based upon the requirements of ADEQ. (*Id.*). In 2002,  
7 ADEQ implemented new policies requiring that wastewater treatment capacity be fully  
8 constructed and operational prior to subdivision approvals. (*Id.*). As a result of this new  
9 policy, ADEQ ceased issuing approvals to construct sanitary facilities to developers  
10 within Johnson Ranch and other developments unless and until Johnson Utilities  
11 constructed the Precision WWTP. (*Id.*). Staff acknowledged that it had no reason to  
12 dispute the Company's contention that it had no choice but to construct the Precision  
13 WWTP. (Tr. Vol. at 1504-1505 [Scott]). Because the decision by Johnson Utilities to  
14 construct the Precision WWTP was a necessary prerequisite to the approval of additional  
15 residential home construction in Johnson Ranch, the Precision WWTP should not be  
16 excluded from plant-in-service on the grounds that it is not used and useful. (Exhibit A-  
17 5 at 36-37).

18 In addition, the construction of the 8-inch sewer force main to serve  
19 approximately 1,834 new homes planned for Silverado Ranch development was  
20 necessary and prudent. (Exhibit A-5 at 37). Construction and installation of the force  
21 main was completed pursuant to the Silverado Ranch Master Utility Agreement. (*Id.*).  
22 Johnson Utilities holds the CC&N to provide wastewater service to Silverado Ranch and  
23 received a *bona fide* request for water service from the developer. Having shown that  
24 the decision to construct and install the sewer line was prudent (and Staff having failed  
25 to assert any facts to contradict such a conclusion), it would be inappropriate to remove  
26 the \$690,186 cost from rate base. (*Id.*).

Staff agrees that a corresponding adjustment to CIAC must be made or a mismatch will occur and result in an understatement of rate base. (Exhibit A-4, Volume III at 7). Out of the \$2,209,026 that the Company has agreed to remove from plant-in-service, \$2,026,026 was funded with AIAC. (Exhibit A-2, Volume III at 13). Of the \$690,186 of additional cost Staff and RUCO propose to remove from plant-in-service, all of this plant was funded with equity and therefore requires no corresponding adjustment to either AIAC or CIAC. (*Id.*). In addition, of the \$1,695,816 of additional cost Staff and RUCO propose to remove from plant-in-service, \$1,433,032 was funded with CIAC. (*Id.*). As a result, a corresponding reduction to CIAC of \$1,433,032 must be made in order to properly match the adjustment to plant-in-service. (Exhibit A-2, Volume III at 13). Excluding the impact of depreciation, if the corresponding adjustments for AIAC and CIAC were made, the net rate base adjustment would be no more than \$952,772 (\$690,186 plus \$1,695,618 less \$1,433,032) (*Id.*). Although RUCO adopted Staff's adjustment for not used and useful, they failed to make the corresponding adjustment to CIAC. (Exhibit A-4, Volume III at 8). By not making the corresponding adjustments to the CIAC account, RUCO's adjustments are one-sided and result in a rate base mismatch as well as a proposed rate base for the Company that is understated. (*Id.*). As described above, RUCO admitted at hearing that their recommendation would result in a mismatch. (Tr. Vol. II at 184 [Moore]).

**d. Post Test Year Plant.**

Both RUCO and the Company propose post test year plant of \$1,021,076 and reclassification of post test year plant costs of \$2,201,386 to test year plant-in-service. (Exhibit A-4, Volume III at 16). During this proceeding the Company discovered that \$2,201,386 of plant originally classified at post test year plant and booked to plant in 2008 was actually placed into service in 2007. (Exhibit A-2, Volume III at 14; *see also* Johnson's Final Schedules, Wastewater Division, Schedule B-2 at 3.4).

1 In its rebuttal filing, this plant was reclassified from post test year plant to test year  
2 plant-in-service. Despite the fact that the Company had identified these projects in its  
3 rebuttal testimony, the Staff engineer did not further evaluate whether these projects  
4 were in fact placed in service in 2007 and instead "left it up to the accounting section to  
5 figure that out." (Tr. Vol. X at 1497 [Scott]). The accounting section in turn testified  
6 that it was the engineer that could not determine when the plant went into service. (Tr.  
7 Vol. X at 1593 [Michlik]). In any event, Staff failed to follow-up to determine whether  
8 such plant was in fact put into service in 2007. The Staff engineer did testify that there  
9 was no question in his mind that the Hunt Highway force main was placed in service in  
10 2007. (Tr. Vol. X at 1498 [Scott]).

11 Next, the actual post test year plant costs for two projects totaling \$1,021,108 (the  
12 Parks Lift Station project at a cost of \$486,714, and the Queen Creek Leach Field project  
13 at a cost of \$534,394). (Exhibit A-2, Volume III at 14-15). The net increase in plant the  
14 Company proposes in its rebuttal filing was \$537,607. (Exhibit A-2, Volume III at 15).

15 The Parks lift station was constructed for use initially by a Fry's shopping center  
16 that was started in 2007. (Exhibit A-5 at 34). Without the completion of the Parks lift  
17 station, the Company would have been forced to pay for vaulting and hauling the  
18 wastewater generated by the shopping center. (*Id.*). The physical transportation of the  
19 wastewater by truck to the Pecan wastewater treatment plant ("Pecan WWTP") would  
20 have been very costly. (*Id.*).

21 All of the excess effluent flows from the Pecan WWTP during the test year which  
22 required disposal were being sent offsite to Shea Homes' Trilogy Encanterra  
23 development during the construction of that project. (Exhibit A-5 at 35). These flows  
24 were well in excess of the demands needed for the Encanterra golf course. (*Id.*). The  
25 Queen Creek Leach Field was constructed to dispose of the excess effluent that Shea  
26 Homes agreed to take during construction to alleviate the 2007 level of effluent disposal

1 needs. (*Id.*).

2 These two projects are revenue neutral and are necessary for reliability purposes,  
3 to serve the test year-end level of customers. (Exhibit A-2, Volume III at 15). In  
4 addition, these two projects have been funded with CIAC. (*Id.*). If the Commission  
5 were to decide to exclude these two projects, a corresponding amount of CIAC should  
6 also be removed. (*Id.*). Ultimately, there will be a net zero impact on rate base. (*Id.*).

7 In contrast, Staff states that “post test year plant in rate base should be granted in  
8 special and unusual circumstances where failure to do so would create an inequity.”<sup>29</sup>  
9 Although the Commission utilizes the historic test year as a starting point, the rules  
10 expressly permit, and the Commission has repeatedly allowed, *pro forma* adjustments,  
11 including post test year plant, in order ensure a proper matching of plant to test year  
12 customers and to more accurately reflect reality during the period the rates will be in  
13 effect. (Exhibit A-2, Volume III at 15).

14 There have been several recent decisions in which post test year plant was  
15 allowed. In each of these decisions, the Commission approved the inclusion of post test  
16 year plant in rate base because the plant was revenue neutral (*i.e.*, necessary for the  
17 provision of service to customers at end of test year) and completed and placed in  
18 service a reasonable time before the hearing so that it can be inspected and audited.<sup>30</sup>  
19 (Exhibit A-2, Volume III at 18). Both the Parks Lift Station and the Queen Creek Leach  
20 Field are revenue neutral (providing service to test year customers) and were completed

21  
22 <sup>29</sup> See Exhibit S-38 at 8.

23 <sup>30</sup> See, e.g., *Rio Rico Utilities, Inc.*, Commission Decision No. 67279 (October 5, 2004); *Arizona*  
24 *Water Company—Eastern Group*, Commission decision No. 66489 March 19, 2004); *Bella*  
25 *Vista Water Company*, Commission Decision No. 65350 (Nov. 1, 2002); *Arizona Water*  
26 *Company—Northern Group*, Commission Decision No. 64282 December 28, 2001); *Paradise*  
*Valley Water Company*, Commission Decision No. 61831 (July 20, 1999); *Far West Water*  
*Company*, Commission Decision No. 60437 (September 29, 1997); *Chaparral City Water*  
*Company*, Commission Decision No. 68176 (September 30, 2005).

1 and placed in service a reasonable time before the hearing, allowing for audit and  
2 inspection. (Exhibit A-2, Volume III at 19).

3 Staff determined that the Parks Lift Station was used and useful during the test  
4 year, but did not make an adjustment to plant-in-service because it was skeptical about  
5 the information it was provided to verify the cost. (Exhibit S-44 at 6). For the Queen  
6 Creek Leach Field, Staff states that it was unable to determine whether the project is  
7 used and useful. (*Id.*). Consequently, Staff did not propose to include this plant in rate  
8 base and recommended the project be looked at in a subsequent case. (Exhibit S-44 at  
9 7). As stated above, this plant is needed to support the 2007 level of customers.

10 RUCO has accepted the Company's post test year plant and has recommended an  
11 increase to post test year plant of \$689,382. Exhibit R-1 at 9. Thus, RUCO recommends  
12 post test year plant of \$3,374,270, consisting of \$2,684,888 from the Company's direct  
13 filing and an additional \$689,382 based on the Company's response to Staff data request  
14 JMM 4-6. (Exhibit A-2, Volume III at 19).

15 **e. Excess Capacity.**

16 Staff has removed the \$5,443,062 original cost of constructing the  
17 1.0 MGD Phase II ("Phase II") of the Santan Wastewater Treatment Plant ("Santan  
18 WWTP") on the basis that Phase II is excess capacity.<sup>31</sup> However the Phase II capacity  
19 will be put to use by late 2009 to treat wastewater flow that will be redirected from  
20 Johnson Utilities' Pecan wastewater treatment plant ("Pecan WWTP"), which is  
21 currently nearing constructed capacity. (Exhibit A-5 at 38). Johnson Utilities has  
22 interconnected its Section 11, Santan and Pecan wastewater treatment plants by force  
23 mains. (*Id.*). This provides Johnson Utilities with greater operational flexibility in  
24 treating wastewater flows in its service area, and it allows the Company to obtain the

25 \_\_\_\_\_  
26 <sup>31</sup> Staff's Final Schedule JMM-WW3.

1 maximum benefit from its combined wastewater treatment capacity before building  
2 costly new treatment plants or plant expansions. (*Id.*). Rather than construct expensive  
3 new capacity at the Pecan WWTP, Johnson Utilities can use available capacity at its  
4 Santan WWTP. (Exhibit A-5 at 39). In fact, Staff testified that if, during the test year,  
5 the Pecan WWTP had 3 million gallons per day of capacity, then Staff probably would  
6 not have recommended any disallowance at that plant. (Tr. Vol. X at 1513 [Scott]).  
7 Johnson Utilities is currently planning/engineering upgrades to the Morning Sun Farms  
8 and Circle Cross lift stations, and planning/engineering the construction of one mile of  
9 new force main, which will enable the Company to redirect current flows from the Pecan  
10 WWTP to the Santan WWTP. (*Id.*). By so doing, Johnson Utilities can delay the costly  
11 construction of an additional 2.0 MGD treatment expansion at the Pecan WWTP. (*Id.*).  
12 Staff concurred that a utility would not want to build plant capacity today if it can  
13 adequately address the capacity issues by moving flow to another plant. (Tr. Vol. X at  
14 1517-1518 [Scott]).

15 If the Commission adopts Staff's position, a corresponding adjustment to AIAC  
16 or CIAC is needed or the adjustment will result in a mismatch and understatement of rate  
17 base. (Exhibit A-2, Volume III at 20). The San Tan plant was funded partially with  
18 CIAC. (*Id.*). The total of CIAC funds used to construct this plant was \$3,697,251. (*Id.*).  
19 A corresponding reduction of \$3,697,251 must be made to CIAC in order to properly  
20 match Staff's plant-in-service adjustment. (*Id.*). The net decrease in rate base,  
21 excluding any depreciation impact, is \$1,745,811 (5,443,062 minus \$3,697,251), not  
22 \$5,443,062 as set forth in Staff's schedules. (*Id.*).

23 **f. Working Capital.**

24 All the parties are in agreement on zero working capital. (Exhibit  
25 A-4, Volume III at 17).  
26

**g. Accumulated Depreciation.**

All the parties are recommending the same depreciation rates. (Exhibit A-2, Volume III at 25). The Company is proposing a reduction in the amount of \$7,560,886 to reflect changes to accumulated depreciation from the plant-in-service adjustments adopted in its rebuttal case. (Exhibit A-2, Volume III at 21; Johnson's Final Schedules, Wastewater Division, Schedule B-1).

**h. Unexpended HUFs (CIAC).**

For the reasons set forth in Section III.A.1.g, the company opposes Staff and RUCO's recommendation to include \$16,505 of unexpended HUFs (CIAC) in rate base.

**i. Amortization of CIAC.**

The Company is in agreement with Staff on the use of a 2.5% composite rate for computing past amortization of CIAC.<sup>32</sup>

**j. Advances-in-aid of Construction ("AIAC").**

The Company has accepted certain plant adjustments from Staff for plant considered not used and useful. (Exhibit A-2, Volume III at 24). Because some of this plant was funded with AIAC, an adjustment to AIAC is necessary in order to avoid a mismatch in rate base. (*Id.*).

**k. Deferred Assets.**

In order to help reduce areas of disagreement between the parties, the Company has accepted Staff's proposed adjustment to remove deferred assets from rate base.<sup>33</sup> (Exhibit A-2, Volume III at 25).

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<sup>32</sup> Exhibit S-44 at 20.

<sup>33</sup> Exhibit S-44 at 21.

**IV. INCOME STATEMENT.**

**A. Water Division.**

**1. Undisputed Items.**

**a. Depreciation Rates.**

All parties recommend the same depreciation rates.

**b. Property Taxes.**

The Company, Staff, and RUCO are all in agreement on the method of computing property taxes. (Exhibit A-2, Volume II at 21).

**c. Purchase Power.**

Company adopts Staff's proposed adjustment to reduce purchased power expense by \$10,620 for purchased power of an affiliate included in expense<sup>34</sup> and adopts RUCO's adjustment to increase purchased power to reflect a known and measurable contractual agreement between the Company and Pinal County for purchased power.<sup>35</sup> (*Id.*).

**d. Contractual Services.**

Company adopts Staff's proposal to reduce contractual services expense by \$5,799.<sup>36</sup> (*Id.*).

**e. Miscellaneous Expense.**

Company adopts Staff's proposal to reduce miscellaneous expense by \$31,192 to reflect the adoption of Staff's proposed adjustment for lobbying, food, entertainment, and sponsorship expenses.<sup>37</sup> RUCO proposes a similar adjustment except it is a reduction of \$1,080 to miscellaneous expense and 30,032 to contractual services

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<sup>34</sup> Exhibit S-38 at 26.

<sup>35</sup> Exhibit R-1 at 18.

<sup>36</sup> Exhibit S-38 at 26.

<sup>37</sup> Exhibit S-38 at 27.

1 for a total expense reduction of 31,112.<sup>38</sup> (Exhibit A-2, Volume II at 21).

2 **2. Central Arizona Groundwater Replenishment District**  
3 **("CAGR") Tax.**

4 The Central Arizona Groundwater Replenishment District ("CAGR")  
5 was established in 1993 by the Arizona legislature to serve as a groundwater  
6 replenishment entity for its members.<sup>39</sup> (Exhibit A-5 at 17). The CAGR provides a  
7 mechanism for landowners and water providers such as Johnson Utilities to demonstrate  
8 a 100-year assured water supply under the State's Assured Water Supply Rules ("AWS  
9 Rules") which became effective in 1995. (*Id.*). As a member of the CAGR, the  
10 landowner or water provider must pay the CAGR to replenish (or recharge) any  
11 groundwater pumped by the member which exceeds the pumping limitations imposed by  
12 the AWS Rules. (*Id.*). The CAGR includes the Phoenix, Tucson and Pinal County  
13 Active Management Areas ("AMAs"). (*Id.*). Johnson Utilities completed the process  
14 for becoming a member service area ("Member Service Area") of the CAGR on or  
15 about June 9, 2000. (Exhibit A-5 at 18).

16 Joining the CAGR is one of the steps in the process of becoming a designated  
17 provider, which means a water provider that has demonstrated to the Arizona  
18 Department of Water Resources ("ADWR") that it has a 100-year water supply. (*Id.*).  
19 The AWS Rules were designed to protect groundwater supplies within each AMA and to  
20 ensure that people purchasing or leasing subdivided land within an AMA have a water  
21 supply of adequate quality and quantity. (*Id.*). Thus, in each AMA, new subdivisions  
22 must demonstrate to ADWR that a 100-year assured water supply is available to serve  
23 the subdivision before sales can begin. (*Id.*). An assured water supply can be

24 <sup>38</sup> Exhibit R-1 at 17.

25 <sup>39</sup> The CAGR is operated by the Central Arizona Water Conservation District, which operates  
26 the Central Arizona Project.

1 demonstrated in two ways. First, the owner of a subdivision can prove an assured water  
2 supply for that specific subdivision and receive a certificate of assured water supply  
3 from ADWR. (*Id.*). Alternatively, the owner of a subdivision can receive service from a  
4 city, town or private water company which has been designated by ADWR as having an  
5 assured water supply. (*Id.*).

6 The costs of the CAGRDR are covered by a replenishment tax or replenishment  
7 assessment levied on CAGRDR members. (*Id.*). Designated water providers such as  
8 Johnson Utilities that serve a Member Service Area pay a replenishment tax directly to  
9 the CAGRDR according to the number of acre-feet of "excess groundwater" they deliver  
10 within their service areas during a year. (Exhibit A-5 at 18-19). The amount of the  
11 replenishment tax is based on CAGRDR's total cost per acre-foot of recharging  
12 groundwater, including the capital costs of constructing recharge facilities, water  
13 acquisition costs, operation and maintenance costs and administrative costs. (Exhibit A-  
14 5 at 19). By statute, the replenishment tax must be calculated separately for each AMA.  
15 (*Id.*). Johnson Utilities is a designated provider in both the Phoenix and Pinal County  
16 AMAs. (*Id.*).

17 In this case, Johnson Utilities removed the \$883,842 CAGRDR tax assessment  
18 from purchased water expense in the test year and proposed that the tax be passed-  
19 through to customers on their monthly bills. (*Id.*). RUCO opposes a pass-through of the  
20 CAGRDR tax assessment. (Exhibit R-1 at 16). Although Staff supports a pass-through of  
21 the CAGRDR tax assessment, Staff proposes 10 conditions. (Exhibit S-43 at 2-3).  
22 Johnson Utilities opposes Staff recommendation 1 which states that the pass-through  
23 shall apply to water sold after October 1, 2009, or shall become effective on the date new  
24 rates from this case become effective, whichever is later. (Exhibit A-7 at 19-20. The  
25 CAGRDR payment for 2008 was due on October 15, 2009 and was paid. (Exhibit A-7 at  
26 20). Thus, the Company believes that the pass-through should commence as soon as its

1 new rates are effective so that the Company can begin collecting funds to put toward the  
2 2008 CAGR D assessment. (*Id.*).

3 Staff recommendation 3 states that Johnson Utilities can only withdraw money  
4 from the new CAGR D account to pay the annual CAGR D fee which is due on October  
5 15 of each year. (*Id.*). However, the Company is concerned that this recommendation  
6 lacks sufficient flexibility to allow for changes in CAGR D's payment policies and other  
7 policies with regard to the use of CAGR D monies. (*Id.*). Johnson Utilities submits that  
8 it should be permitted to withdraw funds from the CAGR D account as necessary to  
9 comply with the conditions of its membership in the CAGR D, as those conditions exist  
10 now or as they may be modified in the future. (*Id.*).

11 Staff recommendation 4 requires that Johnson Utilities provide a semi-annual  
12 report of the new CAGR D account even though the Company makes only a single  
13 annual report to the CAGR D. (*Id.*). The Company believes that a single annual report  
14 provided to the Commission at the time the report is provided to CAGR D would be  
15 sufficient for Staff's verification of the accounting for CAGR D monies collected and  
16 remitted. (*Id.*).

17 Staff recommendation 5 requires that Johnson Utilities provide to Staff, on even-  
18 numbered years, the new firm rates set by the CAGR D for the next two years. (*Id.*).  
19 However, this information is publicly available on the CAGR D's website. (*Id.*).  
20 Johnson Utilities believes that it would be more efficient for Staff to obtain this  
21 information directly from the CAGR D rather than have the Company act as a go-  
22 between to communicate the information. (*Id.*). Compliance with regulatory conditions  
23 adds costs which are ultimately borne by the Company's rate payers. (*Id.*). Thus,  
24 regulatory conditions should not be casually imposed, but only as necessary to achieve  
25 important regulatory objectives. (Exhibit A-7 at 21).

26 Staff recommendation 7 requires that, by July 15 of each year, Johnson Utilities

1 must submit its proposed CAGR D pass-through fee for the Phoenix and Pinal AMAs for  
2 consideration by the Commission, with the Commission-approved amount becoming  
3 effective the following October 1. (*Id.*). The Company believes that this requirement is  
4 unnecessary as the CAGR D assessments are fixed by CAGR D and are not subject to  
5 interpretation. It is not clear what “consideration” and what “approval” the Commission  
6 would exercise with regard to the assessment. (*Id.*). Thus, Johnson Utilities opposes this  
7 condition. (*Id.*).

8 Staff recommendation 8 provides that the CAGR D pass-through will cease if the  
9 CAGR D changes its current method of assessing fees. (*Id.*). However, Johnson Utilities  
10 believes that the termination of the fee need not be automatic. (*Id.*). If CAGR D’s  
11 methods of assessing the fee changes, Johnson Utilities will likewise change the way it  
12 passes through the fee to its customers, consistent with CAGR D’s change. (*Id.*).

13 Staff recommendations 9 and 10 both address how the Commission should  
14 respond to excess CAGR D funds collected by Johnson Utilities. (*Id.*). However, the  
15 method of assessing CAGR D fees is set forth with specificity by CAGR D, and the  
16 CAGR D account balance should not exceed payments to CAGR D. (*Id.*).

### 17 3. Rate Case Expense.

18 All the parties agree on the amount of the rate case expense requested by  
19 the Company at this stage of the proceeding for the Wastewater Division totaling  
20 \$100,000. (Exhibit A-2, Volume II at 23). Both Staff and the Company agree on the  
21 amortization period. (*Id.*). However, RUCO proposes an amortization period of 5 years.  
22 (*Id.*). The Company disagrees with RUCO. (*Id.*). Interestingly, RUCO assumes that the  
23 Company will file a rate case in three years using a 2011 test year when it estimated  
24 CAGR D tax assessment increases. (Tr. Vol. II at 204 [Moore]).

### 25 4. Income Taxes.

26 Both Staff and RUCO propose to exclude income taxes from the

1 determination of the revenue requirement because Johnson is a limited liability company  
2 and is a pass-through entity for income tax purposes.<sup>40</sup> Both Staff's and RUCO's  
3 argument rests on the fact that Johnson itself does not pay income taxes at the company  
4 level, rather the taxable income and tax liability passes through to its member owners  
5 who must pay the tax.

6 The income tax liability arises from the taxable income of Johnson and it is  
7 directly attributable to Johnson Utilities. (Exhibit A-2, Volume II at 23). And while the  
8 tax liability flows through to the member owners, the Company still pays the tax by  
9 reimbursing the members for the tax that must be paid. (Exhibit A-2, Volume II at 24).  
10 In fact, there exists an agreement between Johnson and its member owners that all tax  
11 liabilities attributed and arising from Johnson must be paid by Johnson. (*Id.*). Under  
12 Staff and RUCO approach, an S-Corp or LLC receives a lower revenue requirement and  
13 operating income than a C-Corp resulting in inequities because payment for the tax must  
14 come from somewhere. (*Id.*). Ultimately the tax payment comes from the LLC or S-  
15 Corp itself because members insure their taxes are paid by the entities that generate  
16 them. (*Id.*). In fact, the situation is analogous to a subsidiary C-Corp utility of a parent  
17 holding company whose tax return is consolidated with the parent. (*Id.*). The individual  
18 C-Corp utility does not file a separate tax return, yet this Commission has traditionally  
19 allowed income taxes of the utility to be computed on a stand-alone basis and included  
20 in the revenue requirement. (*Id.*). As a result, rate payers receive an unjustified windfall  
21 from the lower revenue requirement and operating income when income taxes are  
22 excluded. (*Id.*).

23 Rate making should be applied in a manner which produces reasonable and  
24 realistic results no matter what the legal form of the utility is. (Exhibit A-4, Volume II at

25 \_\_\_\_\_  
26 <sup>40</sup> Exhibit S-38 at 29; R-1 at 18-19.

1 19). Inclusion or exclusion of income taxes should not be limited to technical  
2 distinctions; rather it should be based on whether it is fair and does not discriminate.  
3 (*Id.*). The income taxes required to be paid by members of an LLC on a utility's income  
4 are inescapable business outlays that are directly attributed to the utility and are directly  
5 comparable with similar taxes paid by "C" corporations. (*Id.*).

6 It is undisputed that the Commission is constitutionally endowed with very broad  
7 power to prescribe classifications and to establish categories to consider in setting rates  
8 for public service corporations, which includes authority to consider classification for  
9 income tax expenses. A.R.S. § 40-254.01, subd. E; A.R.S. Const. Art. 15, §§ 1 *et seq.*,  
10 14. *Consolidated Water Utilities, Ltd. v. Arizona Corp. Comm'n*, 178 Ariz. 478, 484, 875  
11 P.2d 137, 143 (App. 1993). As such, the Commission has the authority to allow the  
12 recovery of income tax expense on a case by case basis. In *Consolidated Water Utilities,*  
13 *Ltd. v. Arizona Corp. Comm'n*, the Arizona Court of Appeals ruled as follows:

14 In Arizona, the decision to allow or disallow that tax expense is to be made  
15 by the Commission, not the courts. *See also Tucson Gas*, 15 Ariz. at 306,  
16 138 P. at 786 (the Commission has exclusive power over rate cases, and  
17 this "exclusive field may not be invaded by either the courts, the legislative  
18 or executive.").

19 (*Id.*).

20 State Commissions vary as to whether income taxes for pass-through entities are  
21 allowed in cost of service. Although the Company has not conducted an exhaustive  
22 search, Johnson Utilities has identified cases in Florida,<sup>41</sup> Indiana,<sup>42</sup> Kentucky,<sup>43</sup>

23 <sup>41</sup> See for example: *In Re: Proposed Revisions to Rules 25-30.020, . . . , Pertaining to Water*  
24 *and Wastewater Regulation*, Docket No. 911082-WS (1993 WL 590740 (Fla.P.S.C)); *see also Re*  
25 *B& C Water Resources, L.L.C.* Docket No. 080197-WU (2008 WL 3846530 (Fla.P.S.C.)); and  
26 *see also Re Anglers Cove West, Ltd.* Docket No. 070417-WS (2008 WL 3846530 (Fla.P.S.C.)).

<sup>42</sup> See *In re Pioneer Village Water, Inc.*, (1998 WL 999991 (Ind. U.R.C. 1998)).

<sup>43</sup> See *In the Matter of: An Application of Ridge-Lea Investments, Inc. for an Adjustment of*  
*Rates Pursuant to the Alternative Rate Filing Procedure for Small Utilities*, Docket 2008-00364  
(2008 WL 4696006 (Ky.P.S.C.)).

Vermont,<sup>44</sup> and Wisconsin,<sup>45</sup> where the public service commissions in those jurisdictions have disallowed income tax recovery for pass-through entities. However, Johnson Utilities has identified cases in California,<sup>46</sup> Kansas,<sup>47</sup> Michigan,<sup>48</sup> New Jersey,<sup>49</sup> New Mexico,<sup>50</sup> South Carolina,<sup>51</sup> Texas,<sup>52</sup> Washington,<sup>53</sup> and again Wisconsin,<sup>54</sup> where the state commissions have allowed income tax recovery for pass-through entities.

The best rationale for the allowance of income tax recovery for pass through entities was set forth in *ExxonMobil Oil Corp. v. Federal Energy Regulatory Comm'n*, 487 F.3d 945, 376 U.S.App.D.C. 259, (D.C. Cir. 2007). In that case, the Federal Energy Regulatory Commission ("FERC") adopted a policy of full income tax allowances for

<sup>44</sup> See *Re Shoreham Telephone Company Inc.*, Docket No. 6914 (2004 WL 2791514 (Vt.P.S.B.), 181 Vt. 57, 915 A.2d 197 (2006)); see also *Re Vermont Electric Power Company, Inc.* Docket No. 7174 (251 P.U.R.4<sup>th</sup> 331, 2006 WL 1714971 (Vt.P.S.B.)).

<sup>45</sup> See *Re St. Croix Valley Natural Gas, Inc.*, Docket No. 5230-GR-104 (2006 WL 707437 (Wis.P.S.C.)).

<sup>46</sup> California has included an allowance for income tax expenses as part of rates when evaluating utilities that are organized as limited partnerships. See *ARCO Products Co. v. SFPP, L.P.*, 81 CPUC2d 573 at 16 (1998).

<sup>47</sup> See *Re Madison Telephone, L.L.C.*, Docket No. 07—MDTT-195-AUD (2007 WL 2126360 (Kan.S.C.C.)).

<sup>48</sup> See *Re Detroit Thermal, L.L.C.*, Case No. U-13691 (2005 WL 2230278 (Mich.P.S.C.)).

<sup>49</sup> See *Re Maxim Sewerage Corporation BPU*, Docket No. WR97010052 (1998 WL 223177 (N.J.B.P.U.)).

<sup>50</sup> The New Mexico Supreme Court found that a sole proprietorship may include income tax expenses in rate base in "an amount equal to the tax the Company would pay if incorporated" as a standard C corporation. *Moyston v. New Mexico Public Serv. Comm'n*, 63 P.U.R. 3d 522, 412 P.2d 840, 851 (1966).

<sup>51</sup> See *Re Madera Utilities, Inc.*, Docket No. 2003-368-S (2004 WL 1714912 (S.C.P.S.C.)), see also *Re Development Services, Inc.*, Docket No. 2004-212-S (2005 WL 712315 (S.C.P.S.C.)).

<sup>52</sup> "The income taxes required to be paid by shareholders of a Subchapter S corporation on a utility's income are inescapable business outlays and are directly comparable with similar corporate taxes which would have been imposed if the utility operations had been carried on by a corporation." *Suburban Utility Corp. v. Public Utility Comm'n of Texas*, 652 S.W. 2d 358, 364 (1983). Accordingly, the Texas Supreme Court held that the S corporation was "entitled to a reasonable cost of service allowance for federal income taxes actually paid by its shareholders on [the company's] taxable income or for taxes it would be required to pay as a conventional corporation, whichever is less." *Id.*

<sup>53</sup> See *Washington Utilities and Transportation Commission v. Rainer View Water Company, Inc.*, Docket No. UW-010877 (2002 WL 31432725 (Wash.U.T.C.)).

<sup>54</sup> See *Re CenturyTel of the Midwest-Kendall, Inc.*, Docket No. 2815-TR-103 (2001 WL 1744202 (Wis.P.S.C.) see also *Re CenturyTel of Central Wisconsin, L.L.C.*, Docket No. 2055-TR-102 (2002WL 31970289 (Wis.P.S.C.)).

1 limited partnerships. (*Id.* at 952) (emphasis added). FERC determined that income taxes  
2 paid by partners on their distributive share of the pipeline's income are "just as much a  
3 cost of acquiring and operating the assets of that entity as if the utility assets were owned  
4 by a corporation." (*Id.*) (Emphasis added). Consistent with the evidence presented by  
5 the Company in support of allowing income tax expense for pass-through entities, FERC  
6 found no good reason to limit the income tax allowance to corporations, given that "both  
7 partners and Subchapter C corporations pay income taxes on their first tier income."  
8 (*Id.*). Moreover, FERC determined that income taxes paid on the partners' distributive  
9 share of the pipeline's income were properly "attributable" to the regulated entity  
10 because such taxes must be paid regardless of whether the partners actually receive a  
11 cash distribution. See *United States v. Basye*, 410 U.S. 441, 453, 93 S.Ct. 1080, 35  
12 L.Ed.2d 412 (1973) ("[I]t is axiomatic that each partner must pay taxes on his  
13 distributive share of the partnership's income without regard to whether that amount is  
14 actually distributed to him."). (*Id.*). Based on this aspect of partnership law, FERC  
15 concluded that income taxes paid by investors in a limited partnership are "first-tier"  
16 taxes that may be allocated to the regulated entity's cost-of-service. (*Id.*).

17 In *ExxonMobil*, the petitioners argued that these taxes are ultimately paid by  
18 individual investors-not the pipeline-and thus it was improper for FERC to allow income  
19 tax as an expense to the regulated entity. (*Id.*). However, FERC reasonably addressed  
20 this concern, explaining:

21 Because public utility income of pass-through entities is attributed directly  
22 to the owners of such entities and the owners have an actual or potential  
23 income tax liability on that income, the Commission concludes that its  
24 rationale here does not violate the court's concern that the Commission had  
created a tax allowance to compensate for an income tax cost that is not  
actually paid by the regulated utility.

25 (*Id.*). (Emphasis added). FERC also emphasized that "the return to the owners of pass-  
26

1 through entities will be reduced below that of a corporation investing in the same asset if  
2 such entities are not afforded an income tax allowance on their public utility income.”  
3 (*Id.*). FERC determined that “termination of the allowance would clearly act as a  
4 disincentive for the use of the partnership format,” because it would lower the returns of  
5 partnerships vis-à-vis corporations, and because it would prevent certain investors from  
6 realizing the benefits of a consolidated income tax return. (*Id.* at 952-953, 376  
7 U.S.App.D.C. at 266-267).

8 Johnson Utilities submits that it is better policy for the Commission to allow the  
9 inclusion of income tax expense in the Company's revenue requirement.

10 **B. Wastewater Division.**

11 **1. Undisputed Items.**

12 **a. Depreciation Rates.**

13 All parties recommend the same depreciation rates.

14 **b. Property Taxes.**

15 The Company, Staff, and RUCO are all in agreement on the method  
16 of computing property taxes.<sup>55</sup> (Exhibit A-2, Volume III at 26).

17 **c. Purchase Power.**

18 Company adopts Staff's proposed adjustment to reduce purchased  
19 power expense by \$26,003.<sup>56</sup> (*Id.*).

20 **d. Unrecorded Revenues.**

21 The Company agrees to increase revenues by \$65,351. (*Id.*). All of the parties  
22 are in agreement on an adjustment for unrecorded revenues.<sup>57</sup> (*Id.*).

24 <sup>55</sup> Exhibit S-44, Schedule JMM-W21; Exhibit R-1 at 13.

25 <sup>56</sup> Exhibit S-44 at 24.

26 <sup>57</sup> Exhibit S-44 at 22; Exhibit R-1 at 15.

1                                    **e.      Sludge Removal.**

2                                    Company adopts Staff's proposal to remove \$7,688 of costs  
3                                    pertaining to 2008.<sup>58</sup> Staff adopts Company's increase in sludge removal costs of  
4                                    \$31,488 for December 2007 sludge removal invoices erroneously posted in January  
5                                    2008.<sup>59</sup>

6                                    **f.      Contractual Services.**

7                                    Company adopts Staff's proposal to reduce contractual services  
8                                    expense by \$9,022 to reflect the Company's adoption of Staff's proposed adjustment.<sup>60</sup>  
9                                    (Exhibit A-2, Volume III at 27).

10                                   **g.      Miscellaneous Expense.**

11                                   Company adopts Staff's proposal to reduce miscellaneous expense  
12                                   by \$993 to reflect the adoption of Staff's proposed adjustment.<sup>61</sup> (*Id.*). RUCO proposes  
13                                   a similar adjustment except it is a reduction of \$924.<sup>62</sup> (*Id.*).

14                                   **2.      Rate Case Expense.**

15                                   All the parties agree on the amount of the rate case expense requested by  
16                                   the Company at this stage of the proceeding for the Wastewater Division totaling  
17                                   \$100,000. (*Id.*). Both Staff and the Company agree on the amortization period. (*Id.*).  
18                                   However, RUCO proposes an amortization period of five years. (*Id.*). The Company  
19                                   disagrees with RUCO. (*Id.*).

20                                   **3.      Income Taxes.**

21                                   For the reasons set forth in Section IV.A.4 above, the Company disagrees  
22                                   with the recommendation of Staff and RUCO to exclude income taxes from the

23                                   <sup>58</sup> Exhibit S-38, Wastewater at 23.

24                                   <sup>59</sup> Staff's Final Schedule JMM-WW16.

25                                   <sup>60</sup> Exhibit S-44 at 25.

26                                   <sup>61</sup> *Id.*

<sup>62</sup> R-1 at 17.

1 determination of the revenue requirement because Johnson Utilities is a limited liability  
2 company.

3 **V. COST OF CAPITAL.**

4 At the end of the test year, December 31, 2007, Johnson Utilities had adjusted  
5 total capital of \$25,897,122, consisting of \$722,000 long-term debt and \$25,175,122  
6 common equity (Exhibit A-1, Exhibit F at 2; see also A-2, Schedule D-1). Thus, the  
7 Company's capital structure consists of 2.8% debt and 97.2% common equity. (Exhibit  
8 A-2, Volume I at 3; *see also* A-2, Schedule D-1; *see also* Exhibit A-4, Volume I at 2).  
9 The Company is also recommending a cost of equity of 12.0%. (Exhibit A-2, Volume I  
10 at 3). The Company's recommended cost of debt is 8.0%. (*Id.*). Based on a 12.0%  
11 recommended cost of equity, the Company's weighted average cost of capital  
12 ("WACC") is 11.89%. (*Id.*). The Company is recommending that the WACC be used  
13 as the rate of return and applied to the Company's fair value rate base ("FVRB") to  
14 compute the Company's required operating income. (*Id.*).

15 The cost of equity for Johnson cannot be estimated directly because Johnson's  
16 common stock is not publicly traded. (Exhibit A-1, Exhibit F at 4). Therefore, there is  
17 no market data for Johnson. (*Id.*). Consequently, Johnson Utilities applied the  
18 discounted cash flow ("DCF") models and capital asset pricing model ("CAPM")  
19 models using data from a sample of water utilities selected from the Value Line  
20 Investment Survey. (*Id.*). There are six water utilities in Johnson Utilities sample:  
21 American States Water, Aqua America, California Water, Connecticut Water, Middlesex  
22 Water, and SJW Corp. (*Id.*). Johnson Utilities selected these particular utilities because  
23 the Commission's Utilities Division ("Staff") has relied on data for these water utilities  
24 in a number of recent water and sewer utility rate cases. (*Id.*). In calculating cost of  
25 equity, Johnson Utilities' estimate is conservative based upon Johnson Utilities' small  
26 size relative to the six water utilities in Staff's sample group as well as other business

1 risks not captured by the market data are considered. (*Id.*). The higher return for  
2 Johnson takes into consideration the higher business risk in Arizona, especially as the  
3 result of Arizona regulation. (*Id.*).

4 In 1923, the Supreme Court set forth the following criteria for determining  
5 whether a rate of return is reasonable in *Bluefield Water Works and Improvement Co. v.*  
6 *Public Service Commission of West Virginia*, 262 U.S. 679,692-93(1923):

7 A public utility is entitled to such rates as will permit it to earn a return on  
8 the value of the property which it employs for the convenience of the public  
9 equal to that generally being made at the same time and in the same general  
10 part of the country on investments on other business undertaking which are  
11 attended by corresponding risks and uncertainties.... The return should be  
12 reasonably sufficient to assure confidence in the financial soundness of the  
13 utility and should be adequate, under efficient and economical management  
14 to maintain and support its credit and enable it to raise money necessary for  
15 the proper discharge of its public duties. A rate of return may be reasonable  
16 at one time and become too high or too low by changes affecting  
17 opportunities for investment, the money market, and business conditions  
18 generally.

19 In summary, under *Bluefield Water Works*:

- 20 (1) The rate of return should be similar to the return in businesses with  
21 similar or comparable risks;
- 22 (2) The return should be sufficient to ensure the confidence in the  
23 financial integrity of the utility; and
- 24 (3) The return should be sufficient to maintain and support the utility's  
25 credit.

26 (Exhibit A-1, Exhibit F at 14-15).

27 In addition to being widely followed by courts and regulatory commissions, the  
28 Court's discussion of the criteria that should be used to determine a reasonable rate of  
29 return is important because *Bluefield Water Works* involved the application of the "fair  
30 value" standard, which is embodied in the Arizona Constitution. (Exhibit A-1, Exhibit F  
31 at 15). Thus, in discussing the criteria for determining a fair rate of return, the Court  
32 applied the rate of return, judged according these criteria, to the current or "fair" value of

1 the utility's plant and property devoted to public service. (*Id.*)

2 In its Application, the Company recommended a cost of equity of 10.5% based on  
3 financial information from February 2008. (Exhibit A-2, Volume I at 3). The Company  
4 is currently recommending a cost of equity of 12.0%, based on the financial information  
5 available at the time the Company filed its Rebuttal Testimony on March 10, 2009.  
6 (*Id.*). Johnson Utilities' recommendation is based on: (i) cost of equity estimates using  
7 constant growth and multi-stage growth discounted cash flow ("DCF") models and the  
8 capital asset pricing model ("CAPM") for the sample group of publicly traded utilities,  
9 and (ii) Johnson Utilities' review of the economic conditions expected to prevail during  
10 the period in which new rates will be in effect. (Exhibit A-1, Exhibit F at 2).

11 Since the filing of the Company's Application, the cost of equity had increased  
12 substantially, as indicated by the Discounted Cash Flow ("DCF") model and the Capital  
13 Asset Pricing Model ("CAPM") set forth in the Pre-Filed Rebuttal Testimony of Thomas  
14 J. Bourassa. (Exhibit A-2, Volume I at 2). The table below summarizes the results of  
15 Mr. Bourassa's updated analysis using those models:

	<u>Range</u>	<u>Midpoint</u>
16 DCF Constant Growth (earnings growth)	10.6% - 15.6%	13.1%
17 DCF Constant Growth (sustainable	8.3% - 11.9%	10.1%
18 growth)		
19 Two-Stage Growth Model	10.3% - 13.6%	12.0%
20 <b>DCF Average Results</b>	<b>9.7% - 13.7%</b>	<b>11.7%</b>
21 CAPM Historical Market Risk Premium		9.7%
22 CAPM Current Market Risk Premium		23.5%
23 <b>Average CAPM Results</b>	<b>9.3% - 23.5%</b>	<b>16.4%</b>
24 <b>Average Overall Results</b>	<b>9.5% - 18.6%</b>	<b>14.1%</b>
25		
26		

1 (Id.).

2 As set forth in the table above, Mr. Bourassa calculated the midpoint of the range  
3 of cost of equity estimates at 14.1%. (Id.). Given Johnson Utilities' relatively small  
4 size, the regulatory methods and policies used in this jurisdiction (which increase  
5 investment risk), and other firm-specific factors, a cost of equity of 14.1% would be  
6 warranted and could be easily supported by the available data. (Exhibit A-2, Volume I  
7 at 4). Even so, the Company is recommending only 12.0% to reflect Johnson Utilities'  
8 lower financial risk compared to the publicly traded water utilities in Mr. Bourassa's  
9 sample group. (Id.).

10 **A. Cost of Debt and Equity Recommended By Staff and RUCO, and**  
11 **Their Respective Recommendations for the Rate of Return on Fair**  
12 **Value Rate Base.**

13 Staff is recommending an operating margin approach. Staff recommends a 10%  
14 operating margin.<sup>63</sup> This is because Staff is recommending negative rate bases for both  
15 the water and wastewater divisions. (Exhibit A-4, Volume I at 3.) A 10% operating  
16 margin is considered the minimum operating margin employed when rate base is  
17 negative and has been adopted by this Commission in the past (e.g. *Valley Utilities*  
18 *Water Company*, Decision 68309, November 14, 2005). (Id.) Because Staff is  
19 recommending an operating margin approach it has not provided a cost of capital  
20 analysis nor has it directly responded to the Company's position on cost of capital. (Id.).

21 On the other hand, RUCO has recommended a cost of equity of 8.31%, based on  
22 the average cost of equity of its DCF and CAPM results. (Exhibit R-9 at 4). RUCO's  
23 recommended cost of debt is 8.0%, based on the Company's existing debt cost. (Exhibit  
24 R-9 at 5). RUCO is proposing a hypothetical capital structure of 40% debt and 60%  
25 equity. (Exhibit R-9 at 3). Based on a hypothetical capital structure of 40% debt and  
26

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<sup>63</sup> See Exhibit S-38 at 29 and Exhibit S-44 at 31.

1 60% equity, RUCO computed a WACC of 8.18%, which is RUCO's recommended rate  
2 of return on FVRB. (*Id.*).

3 **B. The Company's Disagreements With RUCO's Cost Of Capital**  
4 **Analysis.**

5 **1. Use of Gas Utilities to Develop Cost of Equity.**

6 RUCO has chosen to use ten natural gas companies when developing its  
7 cost of capital analysis. (Exhibit A-2, Volume I at 6). The problem with the analysis is  
8 that because the sample gas utilities are less risky, they are therefore are not comparable  
9 to water utilities. (*Id.*). For example, RUCO's sample water companies have an average  
10 beta of .97, while their sample gas companies have an average beta of just 0.70.<sup>64</sup> That  
11 means that the equity cost for the water utility should be substantially greater than the  
12 gas companies, based on their relative riskiness. (*Id.*). RUCO erroneously assumes that  
13 the gas utilities and water utility have the same systematic risk and are directly  
14 comparable, when they are not. (*Id.*). Gas utilities may be used to estimate the cost of  
15 equity in this case but only if the results produced by the DCF and CAPM models are  
16 adjusted upward to reflect the water utilities' additional risk. (*Id.*). RUCO failed to  
17 make any adjustment to account for the water utilities' additional risk. (*Id.*). By  
18 averaging the results of its equity cost estimate for the water utility sample with his  
19 equity cost estimate for the gas utility sample, RUCO has depressed the cost of equity  
20 estimates. (Exhibit A-2, Volume I at 7). For example, the average of RUCO's CAPM  
21 estimates for the water companies and gas companies are 7.35% and 5.76%, respectively  
22 or a 159 basis point difference. (*Id.*).

23 Based on Value Line data (April 9, 2009), RUCO's sample water companies have  
24 an average beta of .82 while their sample gas companies have an average beta of .62.  
25 (Exhibit A-4, Volume I at 7). By relying on gas utilities, RUCO makes the error in

26 <sup>64</sup> See Exhibit R-8, Schedule WAR-7, 1 of 2.

assuming that a typical gas utility has the same investment risk as a typical water utility. (*Id.*). Using the updated betas for the water and gas sample utilities, and using RUCO's CAPM inputs, the following results would be obtained:

<u>RUCO Water Sample CAPM</u>	<u>Rf</u>		<u>Beta</u>		<u>Rp</u>		<u>K</u>
Geometric Mean MRP	1.6%	+	0.82	X	5.1%	=	5.78%
Arithmetic Mean MRP	1.6%	+	0..82	X	6.8%	=	<u>7.18%</u>
<b>Average Water Utility Sample</b>							<u>6.48%</u>

<u>RUCO Gas Sample CAPM</u>	<u>Rf</u>		<u>Beta</u>		<u>Rp</u>		<u>K</u>
Geometric Mean MRP	1.6%	+	0.62	X	5.1%	=	4.76%
Arithmetic Mean MRP	1.6%	+	0..62	X	6.8%	=	<u>5.82%</u>
<b>Average Gas Utility Sample</b>							<u>5.29%</u>

(Exhibit A-4, Volume I at 7-8). The average of the CAPM estimates for the water companies and gas companies are 6.48% and 5.29%; a 119 basis point difference. (Exhibit A-4, Volume I at 8).

If Johnson Utilities method and inputs are used instead, similar to the method used in the Arizona Water Eastern Group case mentioned in the Rebuttal Testimony of Tom Bourassa (*See* Exhibit A-2, Volume I at 6.), the result is 2.88 basis points, calculated as follows:

<u>Water Sample CAPM</u>	<u>Rf</u>		<u>Beta</u>		<u>Rp</u>		<u>K</u>
Historical MRP CAPM	2.3%	+	0.82	X	7.5%	=	8.45%
Current MRP CAPM	3.7%	+	0..82	X	21.3%	=	<u>21.17%</u>
<b>Average Water Utility Sample</b>							<u>14.81%</u>
<u>Gas Sample CAPM</u>	<u>Rf</u>		<u>Beta</u>		<u>Rp</u>		<u>K</u>
Geometric Mean MRP	2.3%	+	0.62	X	7.5%	=	6.95%
Arithmetic Mean MRP	3.7%	+	0..62	X	21.3%	=	<u>16.91%</u>
<b>Average Gas Utility Sample</b>							<u>11.93%</u>
<b>Average Water Utility Sample</b>							<u>14.81%</u>
<b>Average Gas Utility Sample</b>							<u>11.93%</u>
<b>Difference/Risk Adjustment</b>							<u>2.88%</u>

(Exhibit A-4, Volume I at 8.).

## 2. Disagreements with RUCO's Implementation of the CAPM.

Johnson Utilities has four other concerns with respect to RUCO's CAPM analysis. (Exhibit A-2, Volume I at 8). First, RUCO employs a geometric average in calculating the market risk premium in its CAPM, which depresses its cost of equity estimate downward. (*Id.*). An arithmetic average is the correct approach to use in estimating the cost of capital, as various experts have explained.<sup>65</sup> (*Id.*). In fact, the CAPM was developed on the premise of expected returns being averages and risk being measured with the standard deviation. (*Id.*).

Second, RUCO uses the U. S. Treasury total returns in their computation instead of U.S. Treasury income returns. (Exhibit A-2, Volume I at 9). The market risk premium is calculated by subtracting the risk-free rate from the market return.<sup>66</sup> (*Id.*). RUCO erroneously used the average total return on a Treasury security rather than the average income return. (*Id.*). The reason that an average income return must be used, is because the CAPM is a risk premium methodology that is based on the premise that an investor expects to earn a return equal to the return on a risk-free investment plus a premium for assuming additional risk that is proportional to the security's market risk (*i.e.*, its beta). (Exhibit A-2, Volume I at 10). If the total return on a Treasury security is used instead, additional risk is injected into the CAPM estimate, which is inconsistent with treating the security as a riskless asset. (*Id.*). As a consequence of incorrectly using U.S. Treasury total returns and well as geometric means, RUCO's CAPM estimate dramatically understates the cost of equity for the water utility sample. (*Id.*).

<sup>65</sup> See Richard A. Brealey and Stewart C. Myers, *Principles of Corporate Finance* 156-157 (7th ed. 2003); Roger A. Morin, *New Regulatory Finance* 156-157 (Public Utility Reports, Inc. 2006) ("*Morin*"); Ibbotson SBBI 2008 Valuation Yearbook 77-78.

<sup>66</sup> Exhibit A-1, Exhibit F at 34-36.

Third, RUCO has ignored current market risk. This Commission has consistently approved the use of a current market risk premium in implementing the CAPM in water and wastewater utility rate cases. (Exhibit A-2, Volume I at 10). In Decision No. 68176 (September 30, 2005), the Chaparral City case, the Commission adopted cost of capital used an historic market risk premium and a current market risk premium in its CAPM estimates.<sup>67</sup> (*Id.*). RUCO, however, has ignored current market risk in its CAPM estimates and has relied instead on incorrectly calculated historic market risk premiums. (*Id.*).

Fourth, RUCO's CAPM estimates for both the water and the gas utilities as well as their overall CAPM result are below the current cost of Baa investment grade bonds.<sup>68</sup> (Exhibit A-2, Volume I at 14). In March, 2009, the cost of investment grade bonds was over 8.3%. (*Id.*). The following are the results of RUCO's CAPM analysis shown on Exhibit R-8, Schedule WAR-1:

Geometric mean CAPM estimate - water companies	6.53%
Arithmetic mean CAPM estimate - water companies	8.17%
Geometric mean CAPM estimate - gas companies	5.17%
Arithmetic mean CAPM estimate - gas companies	<u>6.36%</u>
Average Overall CAPM results	6.56%

(*Id.*).

### 3. Disagreements with RUCO's Implementation of the DCF.

RUCO's method of estimating their growth rates is subjective and cannot

<sup>67</sup> See Direct Testimony of Alejandro Ramirez, Docket No. W-02113A-04-0616 (March 22, 2005); Surrebuttal Testimony of Alejandro Ramirez, Docket No. W-02113A-04-0616 (May 5, 2005).

<sup>68</sup> See R-8, Schedule WAR-1.

1 be verified or replicated. In their DCF model, although RUCO relies on projected  
2 sustainable growth in order to estimate the dividend growth rate, the key inputs  
3 necessary to estimate the internal or retention growth rate are not disclosed by RUCO.  
4 (Exhibit A-2, Volume I at 14). Internal or retention growth rates are the expected  
5 growth in dividends due to the retention of earnings. (Exhibit A-2, Volume I at 15).  
6 Retention growth is dependent on the percentage of earnings retained (the retention  
7 ratio) and the expected return on common equity that is applied to the retained earnings.  
8 (*Id.*). Thus, the internal growth rate formula is:

$$\text{Retention growth rate} = br$$

Where:  $b$  = the retention ratio (1-dividend payout ratio)

$r$  = the expected return on common equity

(*Id.*).

The problem with RUCO's implementation of this formula is that they do not  
disclose the retention ratio or the expected return on common equity used to calculate the  
retention growth rate. (*Id.*). As a result, it is impossible to verify the accuracy of his  
calculation of internal growth ( $br$ ). (*Id.*). Although RUCO lists various sources of data,  
and also attaches various materials to their direct testimony,<sup>69</sup> there is no explanation of  
how any of these materials were actually used. (*Id.*). This approach effectively allows  
RUCO to simply select a growth rate that falls somewhere within a broad range and  
cannot be verified. (*Id.*).

#### 4. Disagreements with RUCO's Use of Hypothetical Capital Structure.

RUCO proposes a hypothetical capital structure to account for the lower  
financial risk of Johnson Utilities when compared to the sample of publicly traded water  
companies. (Exhibit R-8 at 57). RUCO's sample of publicly traded water utilities had

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<sup>69</sup> See Exhibit R-8 at 26-28.

1 approximately 46% debt and 54% equity. (*Id.*). RUCO advocates a use of a 40% debt  
2 and 60% equity rather than a 46% debt and 54% equity because RUCO believes that the  
3 higher level of equity in his hypothetical capital structure will compensate the  
4 Company's shareholder for any perceived higher levels of company specific risk.  
5 (Exhibit R-8 at 57-58).

6 Empirical financial data and financial literature suggest that smaller companies  
7 are more risky than larger companies. (Exhibit A-2, Volume I at 16-17). Johnson  
8 Utilities would be considered a very small micro-cap. (Exhibit A-2, Volume I at 17). If  
9 Johnson Utilities cost of equity estimate of 14.1% was used in RUCO's proposed  
10 hypothetical capital structure, the resulting weighted cost of capital would be 11.66%.  
11 Computed as follows:

	<u>Percentage</u>	<u>Cost</u>	<u>Weighted Cost</u>
13 Debt	40%	8.0%	3.20%
14 Equity	60%	14.1%	<u>8.46%</u>
15			11.66%

16 (Exhibit A-2, Volume I at 21).

#### 17 5. Low Interest Rates and the Market Risk Premium.

18 While financial theory suggests that the cost of equity generally moves in  
19 the direction of interest rates, it does not necessarily move in lock step with interest  
20 rates. (Exhibit A-4, Volume I at 4). When the market risk premium ("MRP") increases  
21 it can offset decreases in interest rates. (*Id.*). If the MRP premium increases, decreases  
22 to in interest rates can be offset and visa versa. (*Id.*). Substantial increases in the MRP  
23 can actually offset the interest rate decreases resulting in an overall increase in the cost  
24 of equity. (*Id.*). Cost of equity using the current MRP CAPM approach has been  
25 repeatedly adopted by this Commission in the past (e.g. *Chaparral City Water Company*,  
26

1 Decision 68176, September 30, 2005, *Arizona Water Company – Western Group*,  
2 Decision 68302, November 14, 2005, *Goodman Water Company*, Decision 69404, April  
3 16, 2007, *Far West Water and Sewer Company*, Decision 69335, February 20, 2007,  
4 *Black Mountain Sewer Company*, Decision 69164, December 5, 1005). (Exhibit A-4,  
5 Volume I at 4-5).

6 In contrast, RUCO uses an historical 80 year geometric and arithmetic means as  
7 estimates of the MRP. (Exhibit A-4, Volume I at 5). Thus, RUCO's CAPM approach  
8 fails to consider the current economic and financial conditions which are impacting the  
9 current cost of equity. (*Id.*).

10 In addition, interest rates have not decreased during the pendency of this case.  
11 (*Id.*). Johnson Utilities rebuttal cost of capital update was based on data from mid-  
12 December 2008. (*Id.*). At that time the average of the 5, 7, and 10 year U.S. Treasuries  
13 was 2.34% and the 30 year U.S. Treasury was 3.68%. (*Id.*). Based on the Federal  
14 Reserve data on April 9, 2009, the average of the 5, 7, and 10 year U.S. Treasuries was  
15 2.45% and the 30 year U.S. Treasury was 3.76%.<sup>70</sup> (*Id.*). In addition, Johnson Utilities  
16 initial estimate of the current MRP was 8.9%. (Exhibit A-4, Volume I at 6). As of April  
17 9, 2009 it was over 20%.<sup>71</sup> (*Id.*). Since the first quarter of 2008 there has been  
18 significant turmoil in the economy and the financial markets creating significant  
19 uncertainty. (*Id.*). Uncertainty is risk. (*Id.*). Because of this uncertainty, investors  
20 require higher returns. (*Id.*). As a result, recent low interest rates do not translate into a  
21 low cost of equity.

22  
23  
24 <sup>70</sup> Currently, the average of the 5, 7, and 10 year U.S. Treasuries is 2.8 percent and the 30 year  
U.S. Treasury is 4.26 percent.

25 <sup>71</sup> Mr. Bourassa recently computed the current MRP at 16.9 percent in the Black Mountain  
Sewer Case (SW-02361A-08-0609) ("BMSC"). His recommended COC in the BMSC was  
26 12.4%.

**VI. RATE DESIGN.**

**A. Water Division.**

**1. Company's Proposed Rates.**

The monthly charges at proposed rates are listed below.

<u>All Classes</u> <u>Meter</u> <u>Size</u>	<u>Monthly</u> <u>Minimum</u>	<u>Gallons included</u> <u>in Monthly Minimum</u>
5/8	\$ 14.14	0
3/4	\$ 21.21	0
1	\$ 35.35	0
1 1/2	\$ 70.70	0
2	\$ 113.12	0
3	\$ 226.24	0
4	\$ 353.50	0
6	\$ 707.00	0
8	\$1,131.20	0
10	\$1,626.10	0

The commodity charges and tiers by meter size are:

<u>Residential, Commercial, Industrial and Irrigation Class</u>		
<u>Meter</u> <u>Size</u>	<u>Tier (gallons)</u>	<u>Charge</u> <u>per 1,000 gallons</u>
5/8 and 3/4 Residential	1 to 4,000	\$1.35
	4,001 to 10,000	\$1.80
	Over 10,000	\$2.35
5/8 and 3/4 Commercial, Industrial and Irrigation		
	1 to 10,000	\$1.80
	Over 10,000	\$2.35
1	1 to 25,000	\$1.80

1		Over 25,000	\$2.35
2	1 1/2	1 to 50,000	\$1.80
3		Over 50,000	\$2.35
4	2	1 to 80,000	\$1.80
5		Over 80,000	\$2.35
6	3	1 to 160,000	\$1.80
7		Over 160,000	\$2.35
8	4	1 to 250,000	\$1.80
9		Over 250,000	\$2.35
10	6	1 to 500,000	\$1.80
11		Over 500,000	\$2.35
12	8	1 to 800,000	\$1.80
13		Over 800,000	\$2.35
14	10	1 to 1,125,000	\$1.80
15		Over 1,125,000	\$2.35
16	<u>Standpipe</u>		
17	All Meter Sizes	All gallons	\$2.35
18	<u>Construction</u>		
19	All Meter Sizes	All gallons	\$2.35
20	<u>Non-potable Central Arizona Project Water</u>		
21	All Meter Sizes	All gallons	See Tariff

(Exhibit A-2, Volume II at 26-28).

**B. Wastewater Division.**

**1. Company's Proposed Rates.**

The monthly charges at proposed rates are listed below:

All Classes

<u>Meter Size</u>	<u>Monthly Minimum</u>
5/8	\$ 42.57
3/4	\$ 46.83
1	\$ 59.60
1 1/2	\$ 76.63
2	\$ 123.46
3	\$ 468.31
4	\$ 894.05
6	\$1,234.65
8	\$1,561.00
10	\$2,497.60

The proposed effluent rate is \$0.62 per 1,000 gallons or approximately \$202 per acre foot. (Exhibit A-2, Volume III at 30-31).

**VII. RESPONSE TO SWING FIRST GOLF'S RECOMMENDATIONS.**

Intervenor Swing First Golf ("SFG") makes nine recommendations in this case, most of which are simply outlandish, and all of which should be rejected. While SFG witness Sonn Rowell signed her name to these recommendations, she admittedly did not develop them but rather accepted recommendations that were penned by David Ashton, the managing member of SFG, which is the complainant in a pending proceeding against Johnson Utilities in a separate docket. (Exhibit A-42, SFG Response to Data Request JU 4.23; Tr. Vol. VIII at 1128-1130). Each of the recommendations are addressed below.

**1. Investigation of the Company's Books and Management Practices.**

SFG argues in the Revised Direct Testimony of Sonn Rowell that Johnson

1 Utilities should not be allowed to increase its rates until its management and financial  
2 practices are investigated. (Exhibit SF-40 at 9). Neither Staff nor RUCO made such a  
3 recommendation, and the facts in this case do not warrant such a condition. Staff and  
4 RUCO have each completed their own careful review of the books and records of the  
5 Company. The parties, including SFG, have engaged in substantial discovery, and the  
6 Hearing Division conducted an eleven-day hearing. There has been ample review of  
7 the Company's books and management practices, and no further review is warranted.

8 **2. Immediate Reduction of Water Rates and Payment of Refunds.**

9 SFG witness Rowell argues that Johnson Utilities disregarded a  
10 Commission order (Decision 68235) to file a general rate case by May 1, 2007, using a  
11 2006 test year. (Exhibit SF-40 at 7-8 and 11-12). Ms. Rowell then concludes that the  
12 delay in filing the rate case resulted in the Company "substantially over-earning." (*Id.*).  
13 She recommends that the Commission order the Company to pay refunds to customers  
14 retroactive to an arbitrary date of January 1, 2007. However, Ms. Rowell's  
15 recommendation lacks merit for several reasons.

16  
17 First, Johnson Utilities received authorization to file this rate case by March 31,  
18 2008, using a 2007 test year in a letter from the Commission's Chief Counsel dated  
19 September 18, 2008. (See Kempley letter attached to Exhibit SF-4). Consistent with  
20 Chief Counsel's letter, the Commission's Utilities Division accepted the Company's  
21 filing and subsequently found the rate case application sufficient in a letter dated August  
22 1, 2008. This case proceeded forward with a 2007 test year. (Exhibit A-3 at 2).

23 Second, Ms. Rowell based her assertion that Johnson Utilities is "over-earning"  
24 on the Company's initial application using the 2007 test year. However, Mr. Bourassa  
25 testified that the Company as a whole was actually under-earning, with the wastewater  
26

1 division "under-earning" and the water division "over-earning." (*Id.* at 2-4). Mr.  
2 Bourassa further testified that the bulk of the rate application's proposed decrease in  
3 water revenues was the result of the Company's proposal to exclude nearly \$1.3 million  
4 in CAGR taxes from operating expenses and instead recover those taxes as a pass-  
5 through on customer bills, thereby lowering the Company's revenue requirement. (*Id.*).

6 A third serious problem with Ms. Rowell's recommendation is that it would result  
7 in retroactive ratemaking, which is prohibited in Arizona for good reason. (*Id.*). As Mr.  
8 Bourassa testified, public service corporations in Arizona are authorized the opportunity  
9 to earn a fair rate of return on the fair value of the property, plant and equipment used to  
10 provide service to customers. (*Id.* at 4-5). The authorized return and the rate base to  
11 which it is applied are set at the time of the inquiry, and the authorized return is not  
12 guaranteed. Because the authorized return is not guaranteed, the utility is not permitted  
13 to go back in time to recover shortfalls in revenues, nor can the utility be required to  
14 refund revenues in excess of the authorized return. (*Id.*). The prohibition on retroactive  
15 rate-making prevents the very injustice that Ms. Rowell's recommendation would  
16 create—namely, ordering a refund for alleged over-earning during the 2007 test year  
17 without any consideration of possible under-earning in the years preceding the test year.  
18 It should also be said that this is Johnson Utilities' first rate case, so no authorized return  
19 has previously been established for the Company. (*See* Exhibit SF-42, SFG Response to  
20 Data Request JU 4.22).

22 Finally, Ms. Rowell has no basis to testify regarding SFG's claim that Johnson  
23 Utilities is over-earning because she admittedly did not perform any earnings analysis on  
24 the Company. (*Id.*). For all of these reasons, SFG's recommendation that Johnson  
25 Utilities be ordered to immediately reduce its rates and make refunds to customers  
26

should be rejected.

### 3. Refund of Superfund Tax Collections.

SFG witness Rowell argues that Johnson Utilities should be required to refund so-called Superfund taxes collected from customers since March 4, 2002. (Exhibit SF-40 at 7, 12). Ms. Rowell asserts that the Superfund tax is calculated based on customer usage, and that Johnson Utilities is prohibited from passing through usage-based taxes to its customers by Decision 64598 (March 4, 2002), which she alleges authorizes only the pass-through of revenue-based taxes. (*Id.*). However, Mr. Bourassa testified that the Superfund tax is a transaction privilege sales tax that may be collected by the Company pursuant to Arizona Administrative Code R14-2-209.D.5, which authorizes a utility to collect from its customers a proportionate share of any privilege, sales or use tax. (Exhibit A-3 at 5-6). Mr. Bourassa further testified that the Superfund tax is reported on Arizona Transaction Privilege Tax Form TPT-1 under Business Class Code 041, and that guidance on this tax is found in Arizona Department of Revenue Transaction Privilege Tax Ruling TPR 93-20. (*Id.*). This testimony by Mr. Bourassa that the Superfund tax is a transaction privilege sales tax was un-refuted by SFG.

Mr. Bourassa also testified that in his experience, all water utilities collect Superfund taxes as a pass-through on customer bills, and that this is the first time he has encountered a party to a rate case challenging the collection of the tax from customers. (*Id.*). Moreover, neither Staff nor RUCO has recommended against collecting Superfund taxes from customers as a pass-through on the bill. It should also be noted that Decision 64598, which forms the basis for Ms. Rowell's recommendation, addressed a request by Johnson Utilities for permission to pass through CAGR taxes to the Company's customers, and did not address the collection of Superfund taxes.

SFG has failed to prove its claim that Johnson Utilities illegally collected Superfund taxes from customers, and its recommendation that the Company be ordered

1 to refund such taxes collected since the date of Decision 64598 should be rejected.

2 **4. Disallowance of Pecan WWTP in Rate Base.**

3 SFG witness Rowell argues that the Pecan WWTP should be disallowed in  
4 rate base until Johnson Utilities has demonstrated that the plant "is no longer a threat to  
5 public safety." (Exhibit SF-40 at 12-13). Ms. Rowell's assertion regarding the safety of  
6 the plant derives from notices of violation ("NOVs") issued by ADEQ pertaining to the  
7 Pecan WWTP. However, the existence or absence of NOVs is not the standard for  
8 excluding or including plant in rate base. The relevant standard, as correctly stated by  
9 Mr. Bourassa in his Supplemental Rebuttal Testimony, is whether the plant is "used and  
10 useful" in providing service to customers. (Exhibit A-3 at 6). The evidence in this case  
11 clearly establishes that the Pecan WWTP is used and useful, and neither SFG nor any  
12 other party has provided credible controverting evidence.

13 By her own admission, Ms. Rowell has no training in the design, operation, or  
14 construction of wastewater collection systems or wastewater treatment systems, nor is  
15 she familiar with the statutes and rules that govern wastewater treatment plants. (Tr.  
16 Vol. VIII at 1086-1089). Ms. Rowell did not inspect the Pecan WWTP. (*Id.* at 1107-  
17 1108; Exhibit A-42, SFG Response to Data Request JU 4.26). Ms. Rowell did not ask  
18 any data requests of Johnson Utilities. (Tr. Vol. VIII at 1108). Ms. Rowell provides no  
19 credible evidence that the Pecan WWTP is excess capacity or that it is not used and  
20 useful. There is simply no basis to adopt SFG's recommendation that the Pecan WWTP  
21 be disallowed in rate base.

22 It should also be noted that at the hearing, Mr. Tompsett testified that Johnson  
23 Utilities has completed all required action items and submitted all required confirming  
24 information to ADEQ pertaining to the NOVs at the Pecan WWTP. (Tr. Vol. VII at  
25 1034-1036). Mr. Tompsett further testified that the Company is only awaiting formal  
26 closure of the NOVs. (*Id.*). There is no testimony or evidence in the record which

controverts this testimony by Mr. Tompsett.

**5. Defamation Lawsuits Against Customers.**

SFG witness Rowell recommends that Johnson Utilities be ordered to dismiss pending defamation lawsuits against customers and pay the court costs and legal fees of those customers. (Exhibit SF-40 at 9). This recommendation rests wholly on unsubstantiated and inflammatory statements by Ms. Rowell that the lawsuits are frivolous, and that they are intended by the Company to harass and intimidate customers. (*Id.* at 6, 13). The recommendation lacks all credibility given that (i) Ms. Rowell never reviewed a copy of the defamation complaint against the customers (nor did she ask for a copy of the complaint); (ii) Ms. Rowell admittedly has no specific knowledge of the specific allegations contained in the complaint; (iii) Ms. Rowell does not know the elements required to prove a defamation claim; (iv) Ms. Rowell provided no legal authority which would allow the Commission to order Johnson Utilities to dismiss a pending lawsuit; and (v) Ms. Rowell provided no legal authority which would allow the Commission to order Johnson Utilities to pay another party's legal fees. (Tr. Vol. VIII at 1091, 1122-1123; Exhibit A-42, SFG Response to Data Request JU 4.27). Simply stated, Ms. Rowell knows nothing about the facts surrounding the defamation lawsuits that would qualify her to make her recommendation, and it should be rejected.

**6. Fines for Alleged Disregard of Public Service Obligations, Environmental Laws and Commission Orders.**

SFG witness Rowell alleges that Johnson Utilities disregarded its public service obligations, environmental laws and Commission orders, and recommends that the Company be fined. (Exhibit SF-40 at 9). However, SFG has failed to present credible evidence that fines are warranted against Johnson Utilities. While Johnson Utilities acknowledged mistakes in certain billings to SFG, Mr. Tompsett testified that those mistakes were inadvertent and that appropriate billing credits have been given to

1 SFG. Mr. Tompsett also testified that Johnson Utilities has completed all required action  
2 items and submitted all required confirming information to ADEQ on all outstanding  
3 NOVs, and that the Company is only awaiting formal closure of the NOVs. Ms.  
4 Rowell's assertions that Johnson Utilities disregarded Decisions 68235 and 64598, which  
5 are discussed above, has already been refuted by the Company. Neither Staff nor RUCO  
6 have proposed fines in this case. Thus, SFG's recommendation that the Commission  
7 impose fines on Johnson Utilities should be rejected.

8 **7. Reducing Johnson Utilities' Return on Equity.**

9 SFG witness Rowell recommends that Johnson Utilities be penalized with  
10 a reduced return on equity. (Exhibit SF-40 at 9). The absurdity of this recommendation  
11 is borne out by the fact that Ms. Rowell devotes only two short lines to it in her Revised  
12 Direct Testimony. Lowering a utility's return on equity as a penalty would violate the  
13 longstanding standards set forth in *Federal Power Comm'n v. Hope Natural Gas Co.*,  
14 320 U.S. 591, 604-05, 64 S.Ct. 281, 289 (1944) and *Bluefield Waterworks & Imp. Co. v.*  
15 *Public Service Comm'n of West Virginia.*, 262 U.S. 679, 692, 43 S.Ct. 675, 679 (1923).  
16 These landmark U.S. Supreme Court rulings established the basic criteria applicable to  
17 determining a fair and reasonable rate of return. As stated by Mr. Bourassa in his  
18 Supplemental Rebuttal Testimony:

19 In short, a utility's authorized rate of return should satisfy the following:

- 20 (1) The rate of return should be commensurate with returns on  
21 investments in other enterprises having corresponding risk;
- 22 (2) The return should be sufficient to ensure confidence in the financial  
23 integrity of the utility and to maintain and support the utility's  
24 credit; and
- 25 (3) The return should enable the utility to attract capital necessary for  
26 the proper discharge of its duties. (Exhibit A-3 at 7).

1 Likewise, under the Arizona Constitution, "the Commission is required to find the  
2 fair value of the company's property and use such finding as a rate base for the purpose  
3 of determining what are just and reasonable rates." *Arizona Corp. Comm'n v. Arizona*  
4 *Public Service Co.*, 113 Ariz. 368, 370, 555 P.2d 326, 328 (1976) (citing *Simms v.*  
5 *Round Valley Light & Power Co.*, 80 Ariz. 145, 294 P.2d 378 (1956)). "Thus, the rates  
6 established by the Commission should meet the overall operating costs of the utility and  
7 produce a reasonable rate of return [or operating margin]. It is equally clear that the  
8 rates cannot be considered just and reasonable if they fail to produce a reasonable rate of  
9 return or if they produce revenue which exceeds a reasonable rate of return." *Scates v.*  
10 *Arizona Corp. Comm'n*, 118 Ariz. 531, 534, 578 P.2d 612, 15 (Ct. App. 1978) (emphasis  
11 added).

12 By her own admission, Ms. Rowell conducted no financial analysis of any kind  
13 on Johnson Utilities' rate case application and, therefore, she has no basis to opine on  
14 what rate the Commission should authorize for a return on equity. (*Id.*; Exhibit A-42,  
15 SFG Responses to Data Request JU 4.28, JU 4.30 and JU 4.31). Ms. Rowell has not  
16 cited any legal authority that would allow the Commission to penalize a public service  
17 corporation by reducing its return on equity, nor has she cited any prior decision where  
18 the Commission has adopted such a recommendation. SFG's recommendation should be  
19 rejected.

#### 20 8. Surrender of Certificate of Convenience and Necessity.

21 SFG witness Rowell recommends that following completion of the SFG-  
22 recommended management and financial audits of Johnson Utilities, the Company be  
23 required to demonstrate why it should not surrender its CC&N. (Exhibit SF-40 at 9).  
24 However, a CC&N may not be revoked without proper notice and a hearing. This rate  
25 case has not been noticed as a CC&N deletion case, and any discussion regarding a  
26 deletion of the CC&N is outside the scope of this proceeding.

9. **Bifurcation of Rate Case Proceeding into Phases.**

SFG witness Rowell recommends that the Commission bifurcate this rate case into two phases. (Exhibit SF-40 at 9). Johnson Utilities believes that this recommendation is moot given that a hearing in this rate case has been completed and the case is proceeding toward a final order.

**VIII. MISCELLANEOUS ISSUES.**

**A. Water Division.**

**1. Discontinuance of Hook-Up Fees.**

The Company does not agree with Staff's proposal to discontinue HUFs. The current HUF only covers from 40-45% of the costs of the subdivision. (Exhibit A-5 at 30). The remaining 55-60% of the cost of the subdivision is funded by equity. (*Id.*). The water HUF account still has a balance of \$6,931,078 at the end of 2007; however these fees have been collected on developments where construction has stopped due to current market conditions. (Exhibit A-5 at 31). In the coming years, Johnson Utilities has ongoing obligations to build plant capacities for the development that were started during the real estate boom, and with the HUFs already used for the initial plant capacities, the remaining plant will be funded by equity. (*Id.*). Staff asserts "due to the company's inadequate accounting records, Staff is recommending that a certified public accounting firm attest to the company's membership equity level of 40% in order for the company to reapply for HUFs. (Exhibit S-39 at 15). Yet, on an annual basis, Johnson Utilities provides a report to the Commission detailing its collection and disbursement of HUFs. (Exhibit A-7 at 7). In 2006, Mr. Jim Dorf of the Commission's Utilities Division Staff conducted a thorough audit of the Company's HUF accounts and found nothing improper or amiss. (*Id.*). While Mr. Dorf indicated to Mr. Brian Tompsett that he would be producing a written report regarding the HUF accounts, the Company never received anything in writing from the Commission. (*Id.*). However, Mr. Dorf confirmed with

1 Mr. Tompsett that the audit had not disclosed anything unusual or improper regarding  
2 the way that Johnson Utilities was collecting, using and accounting for its HUFs. (*Id.*).

3 **2. Water Loss for Johnson Ranch System.**

4 Staff is recommending that based upon water loss at the Johnson Ranch  
5 system, the Company should begin a 12-month monitoring exercise to monitor water  
6 loss from October 1, 2009 through October 1, 2010. (S-36, Exhibit MSJ at 8). Staff  
7 asserts that “for the Johnson Ranch system, the company reported 2,438,732,000 gallons  
8 pumped and 1,965,312,000 gallons sold, resulting in water loss of 19.4%. (*Id.*). Yet, the  
9 1,965,312,000 gallons sold does not include construction water sales and irrigation water  
10 sales from the Company’s construction billing cycle. (Exhibit A-5 at 32). After  
11 adjusting for these additional water sales, the actual percentage of “non-account” water  
12 for the Johnson Ranch system for 2007 was under 10%. (*Id.*). In any event, Johnson  
13 Utilities has already addressed the water loss issue in the 2008 water use data sheet for  
14 the Johnson Ranch system which was recently submitted with its 2008 annual report.  
15 (Exhibit A-7 at 15). This report shows lost and unaccounted water for the Johnson  
16 Ranch system of only approximately 2%, which is well below the Commission’s limit of  
17 10%. (*Id.*). It is not 19.4% as proposed by Staff. (S-36, Exhibit MSJ at 8). In essence  
18 the 12-month monitoring exercise has already been completed and submitted to the  
19 Commission. Thus, there is no need for the monitoring exercise recommended by Staff.

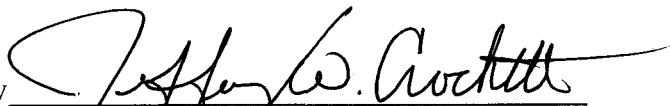
20 **B. Wastewater Division.**

21 **1. Discontinuance of Hook-up Fees.**

22 For the reasons set forth in Section VIII.A.1, the Company does not agree  
23 with Staff’s proposal to discontinue HUFs.  
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25  
26

1 RESPECTFULLY SUBMITTED this 20th day of November, 2009.

2 SNELL & WILMER L.L.P.

3  
4 By 

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12 20th day of November 2009, with:

13 Docket Control  
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16 Phoenix, Arizona 85004

17 COPIES of the foregoing hand-delivered this  
18 20th day of November, 2009, to:

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20 Hearing Division  
21 ARIZONA CORPORATION COMMISSION  
22 1200 W. Washington Street  
23 Phoenix, Arizona 85007

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